CANADIAN
ENERGY
RESEARCH
INSTITUTE

3512 - 33 ST. N.W., Calgary, Alberta — T2L 2A6

Phone: (403) 282-1231

WORKING PAPER 83-3

DEVELOPMENT OPTIONS FOR BRITISH COLUMBIA COAL

KRISTI E. VARANGU

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Acknowledgements

Research on this working paper was begun by Dr. Farhood Rahnama, former CERI staff economist. I wish to thank him for setting me on the right track. Thanks are also due to my supervisor, Charles Slagorsky for his advice, direction and patience.

Preface

The Canadian Energy Research Institute (CERI) is a co-operative research organization sponsored by five parties: Energy, Mines and Resources Canada, the Alberta Department of Energy and Natural Resources, the Private Energy Research Association (composed of corporate and individual members from oil, gas, coal, electrical, nuclear energy and pipeline companies), The University of Calgary and the Ontario Ministry of Energy. The objectives of the Institute are to develop an economic research capability and to conduct studies that will assist industry and government in dealing with energy problems. The research program of the Institute is developed by a Board of Directors named by the sponsoring organizations. The content of the individual studies is, however, the responsibility of the authors.

In addition to undertaking studies in energy economics funded collectively by the five Institute sponsors, CERI carries out research for clients on a contractual basis.

This working paper is the third and last in a series addressing development options for coal in various regions of Canada. Two working papers released earlier in 1983 dealt with the Maritime provinces and Alberta/Saskatchewan. The present phase of CERI's coal research will culminate with a study providing a comprehensive analysis of development options for Canadian coal. The study will combine information reported in the working papers with additional material.

EXECUTIVE SUMMARY

The purpose of this paper is to analyze the short and long-term options available to British Columbia coal producers. Both domestic and export markets are considered.

Included in the examination of the export development option are such factors as the cost of transporting coal to tidewater--a distance of at least 1100 kilometres from most provincial coalfields--and the potential of British Columbia coal for market penetration in Europe, Asia and Latin America. Metallurgical and thermal coals are both considered: the first as an input to the making of steel, the second as an energy source.

Domestic options discussed include the use of thermal coal for electricity generation, as a heat-energy source for energy-intensive industry, and for liquefaction. The sale of metallurgical coal from British Columbia to steelmakers in central Canada is also considered.

The analysis indicates that the options which are economically viable are: utilization of thermal coal by British Columbia's energy-intensive industries, and increased overseas exports of both coal types. Utilizing British Columbia coal for coal-fired electricity generation and for conversion to liquid fuels is too expensive at this time, given the alternatives of hydro generation and the availability of crude oil and natural gas.

INTRODUCTION

Coal is a unique natural resource in that reserves are abundant and distributed worldwide. Tables 1 and 2 show the countries with the greatest recoverable reserves and the major exporting nations. It is interesting to note that Canada is among the major exporters, although in terms of reserves levels this country stands only twelfth in the world.

There are two types of coal: metallurgical and thermal. The former, also called coking coal, is used in the production of pig iron and subsequently an input to the steelmaking process. Demand is directly related to the demand for steel. Thermal coal is utilized as an energy source for electricity generating plants and by some industries. Demand is directly related to the demand for energy, and the price of alternative fuels.

British Columbia is fortunate to possess significant coal resources, although only one region--the Southeast--is commercially developed at this time. Provincial reserves include both metallurgical and thermal coal, although quality considerations restrict market penetration of the latter. The favourable coking characteristics of much of British Columbia coal, will mean that the metallurgical coal market will continue to encompass the greater portion of British Columbia coal production.

Before any decision is made to commit capital funds to a resource development project, alternative options must be examined. The purpose of this paper, therefore, is to describe and assess the development options for British Columbia coal resources.

TABLE 1

WORLD ESTIMATED RECOVERABLE RESERVES OF COAL
(million tonnes)

		Rank			Rank
U.S.S.R.	283 063	1	Poland	47 379	7
U.S.A.	271 227	2	South Africa	30 727	8
China	120 272	3	East Germany	30 495	9
Australia	72 088	4	Yugoslavia	20 135	10
West Germany	71 846	5	India	17 248	11
United Kingdom	54 664	6	Canada	7 175	12

SOURCE: The World Energy Conference 1980 Updated, as reported in the 1981 International Energy Annual, DOE/EIA - 0219 (81) (Washington: U.S. Department of Energy), September 1982.

TABLE 2

COAL EXPORTS FROM MAJOR PRODUCING NATIONS
(million tonnes)

	1980	1981
U.S.	89.9	110.3
Australia	43.2	47.4
South Africa	29.15	29.90
Poland	31.0	15.1
U.S.S.R	23.9	N/A
Canada	14.3	16.3
E.E.C	0.858	3.640

SOURCE: Merrill Lynch, Pierce, Fenner and Smith, Inc., International Coal Data, 1982.

Chapter 1

COAL RESOURCES AND PRODUCERS

British Columbia's coal resources are extremely large and widely distributed. This province has the second largest coal deposits in Canada (after Alberta), but only one region is commercially developed at this time. With expansion of the coal export market, a number of new coal fields are being developed.

Coal in British Columbia is found in several regions and ranges in rank from lignite to anthracite. There are five primary coal fields in British Columbia that are discussed in Section 1.2. The coal characteristics of some of these reserves are discussed in the following sections.

Table 1.1 shows the most recent (1983) coal reserves and resources statistics available from British Columbia Energy Mines and Petroleum Resources.[1] It should be noted that the definitions of reserves and resources utilized by the British Columbia government differ somewhat from those used by Energy, Mines and Resources Canada hence the statistics will differ as well.[2] The provincial parameters are actually somewhat more restrictive than those of the federal government.

A discussion of coal quality will follow the reserves description. The bulk of British Columbia coal exports have been metallurgical coal and there is one main reason (among others) which has helped develop this pattern. Both the Northeast and Southeast regions have a large proportion of medium-volatile bituminous coal with good coking characteristics. When examining the development of mines for thermal coal production and especially for export, one must assess the desirability of the coal by major users in light of its often low calorific value.

TABLE 1.1

ESTIMATES OF COAL RESOURCES OF IMMEDIATE INTEREST IN BRITISH COLUMBIA
(megatonnes)

Resource	Metallurgical	Thermal	Total
Measured Reserves[a]	1 500	1 240	2 740
Resources-Indicated[b] and Inferred[c]	28 400	8 030	36 430

SOURCE: Energy Mines and Petroleum Resources, British Columbia, 1983

[a]Measured Reserves: Tonnages are computed with maximum data point spacing of 375 meters. Properties must have undergone complete feasibility studies, with sufficient exploration data acquired to do a detailed mine design and cost analysis.

[b]Indicated Resources: Tonnages are computed with 750 metre data point spacing and for which feasibility studies need not be complete but are in progress.

[c]Inferred Resources: Tonnages are computed with greater than 750 metres between data points but at a maximum depth of 750 metres. Properties of less than 1 million tonnes of coal are classified under this category.

1.1 Major Coal Fields in British Columbia[3]

Major coal fields in British Columbia can be placed under two regional classifications: the Southeast and Northeast regions. There are also three lesser regions: Southcentral, Northcentral and Coastal, which have potentially significant coal deposits. The purpose of this section is to identify the types and provide quantitative information on the British Columbia coal fields. Figure 1.1 displays the major coal deposits of the province.

1.1.1 Southeast Region (East Kootenay)[4]

Currently this is British Columbia's single source of coal production. Some major coal deposits in this region are: Sage Creek, Dominion Coal Block, Hosmer Wheeler, Corbin, Sparwood Ridge, Natal Ridge, Line Creek, Fording River and Elk River. Production from the East Kootenay coalfields began in the last century and, since the early 1960s, the region has been a major source of metallurgical coal for export. There are three coalfields in the region: Flathead, Crowsnest and Elk Valley. The coals in the region are mainly medium-volatile bituminous coal with calorific value of 26.5 to 32 megajoules per kilogram (MJ/kg). A broad range for material content of the raw coal in this region on an air-dried basis is:[5]

Ash	9.4 - 29.3%
Moisture	0.5 - 1.0%
Volatile matter	19.2 - 22.4%
Fixed carbon	50.2 - 68.6%
Sulphur	0.5 - 0.7%

One of the main producing mines in the area is B.C. Coal Ltd.'s Balmer Mine, with operations on a single seam. A typical 'as received analysis' of the Balmer seam is:

Ash	18.8%
Volatile matter	18.4%
Fixed carbon	62.8%
Sulphur	0.66%

Sources: Energy, Mines and Resources Canada, Coal Resources and Reserves of Canada, Report ER 79-9 (Ottawa: Supply and Services Canada, December 1979), and The Coal Task Force, Coal in British Columbia: A Technical Appraisal (Victoria: Department of Mines and Petroleum Resources, March 1976.)

Figure 1.1: British Columbia Coal Fields and Deposits, by Age

Southeastern coal is usually unoxidized with caking characteristics, and is therefore suitable for metallurgical coke production. The oxidized coal and the metallurgical by-product coal are valuable as thermal coal. The region contains reserves of 1030 million tonnes of metallurgical and 165 million tonnes of thermal coal. Resource figures are appreciably higher at 21 500 MMt of the former and 3800 MMt of the latter.[6]

The Dominion Government Coal Blocks are two parcels of coal-bearing lands in the Crowsnest Pass Coalfield and the Kootenay District whose mineral and surface rights are held by the government of Canada. These lands were conveyed under the Crowsnest Pass Agreement of 1897 in exchange for a federal subsidy of $11,000 per mile of rail line constructed by Canadian Pacific Railways on its proposed route between Lethbridge, Alberta and Nelson, British Columbia.[7] One reason the Crown properties have not been developed to date stems from a stipulation of the Agreement whereby the coal is to be sold at a price of $2.00 or less per ton.[8] Discussion regarding these properties has escalated over the years as the British Columbia government has contested federal jurisdiction over provincial resources. It appears that some decision by the Canadian government may be imminent.

1.1.2 Northeast Region (Peace River)

The Peace River Coalfield consists of several significant coal deposits including: Quintette, Sukunka, Bullmoose, Willow Creek, Hasler Creek, Carbon Creek, Burnt River, Goodrich, Monkman, Saxon and Belcourt.

The coals of this region fall into the ranks of low to medium-volatile bituminous. Most of the coals are of good unoxidized quality and hence are suitable for coking.

Stimulated by recent export contracts, the Northeast region has become the centre of attention and mining developments are in progress. While the main purpose of exploiting these deposits is to export metallurgical coal, the oxidized coal which does not have the requisite caking properties will be exported as thermal coal.

Typical material content of the Bullmoose, Quintette and Yukon deposits on an air-dried basis is:

Ash	11.1 - 39.8%
Moisture	0.5 - 0.8%
Volatile matter	16.3 - 23.1%
Fixed carbon	43.1 - 69.2%
Sulphur	0.4 - 0.8%

Coals from Peace River have a calorific value of about 28 to 33.5 MJ/kg with approximately 85 percent suitable for coking. Total reserves of the region are about 575 million tonnes (470 MMt of metallurgical and 105 MMt of thermal coal). Total resources are 6900 MMt of metallurgical and 1200 MMt of thermal coal.[9]

1.1.3 Other Significant Regions

Northcentral Region

The Northcentral region is composed of the Groundhog and Bowron coal deposits and the Telkwa coalfield. Coals in this region are of thermal quality. The Groundhog deposits contain anthracite, semi-anthracite or low-volatile bituminous coal with calorific value of about 32.5 MJ/kg. The coals have no caking properties and hence are most commonly utilized as thermal coal.

The Telkwa coal field contains high-volatile B bituminous coal with calorific value of about 30 MJ/kg. Since the coal has been oxidized over its life, it is not suitable for metallurgical purposes and is only valuable as thermal coal. The Bowron River coals are high-volatile B bituminous coal with calorific value of 28 MJ/kg. The typical material content of the regional coals on an air-dried basis is:

	Bowron	Groundhog	Telkwa
Ash	23.8%	41.7%	12.3%
Moisture	3.62%	0.47%	1.40%
Volatile matter	26.7%	5.36%	29.4%
Fixed carbon	34.1%	51.40%	56.9%
Sulphur	1.34%	1.17%	0.55%

Combined area resources are 1108 MMt of thermal quality coal.[10]

Southcentral Region

Hat Creek coal is a low grade lignite to sub-bituminous coal, which due to its high ash content and low calorific value, is only economical for mine-mouth use. British Columbia Hydro and Power Authority, the licence holder for this field, has studied the erection of a coal fired power station in this area.

Typical air-dried material content of the field is:

Ash	27.6%
Moisture	20.7%
Volatile matter	28.5%
Fixed carbon	23.2%
Sulphur	0.8%

The Merritt coalfield, south of Hat Creek, had been a high-volatile B bituminous coal producing field from 1906 to 1963 until seam correlation made underground mining too difficult. Coals of lower rank are also present, but a typical analysis of the high-volatile bituminous coal is:

Ash	7.55%
Moisture	2.22%
Volatile matter	37.5%
Fixed carbon	52.4%
Sulphur	0.30%

Estimated resources are 18 million tonnes.[11]

The Similkameen coalfield is comprised of two separate basins--Tullameen and Princeton. The coals have an average calorific value of 25.5 MJ/kg, making them suitable for thermal use. Tulameen is primarily of sub-bituminous rank with material content as follows:

Ash	42.2%
Moisture	5.95%
Volatile matter	23.9%
Fixed carbon	27.9%
Sulphur	0.46%

Princeton field coal ranks from lignite to sub-bituminous with a typical analysis of:

Ash	60.2%
Moisture	17.4%
Volatile matter	12.8%
Fixed carbon	9.52%
Sulphur	0.79%

Coastal Region

The Westcoast region is composed of Suquash, Comox, and Nanaimo Coalfields on Vancouver Island and coal deposits on Graham Island.

The Suquash coal deposits rank as lignite with calorific value of 16 MJ/kg. This is the site of the province's first coal mining operation. The Comox and Nanaimo coalfields contain high-volatile bituminous coal with calorific values of 30 MJ/kg and 23 MJ/kg, respectively. Most coals in this region are non-coking, and only useful as thermal coal. Typical material content of the coal in Vancouver Island on an air-dried basis is:

	Suquash	Comox
Ash	47.6%	28.4%
Moisture	0	1.94%
Volatile matter	25.4%	30.5%
Fixed carbon	26.9%	38.6%
Sulphur	2.27%	1.92%

The Graham Island coal deposits of the Queen Charlotte Islands have coal which ranks from lignite to anthracite at various portions of the island. Typical analyses of the three types found are:

	Lignite	Bituminous	Anthracite
Ash	2.3%	16.1%	6.6%
Moisture	18.5%	1.2%	1.8%
Volatile matter	44.2%	36.2%	4.7%
Fixed carbon	34.7%	46.5%	85.7%
Sulphur	0.3%	1.0%	0.9%

1.2 Coal Quality

Coal quality varies greatly within British Columbia. Nonetheless, a few generalizations can be made. Development has historically centred on metallurgical coal mines as the quality of coal for coking is most often very good. One such advantageous characteristic is a low sulphur content. It should be realized that a designation of 'low' or 'high' is quite subjective, as some countries may have more stringent quality regulations than others. As well, the qualification 'low' means entirely different assessments with regard to metallurgical and thermal coals. For example, a low ash content for thermal coal is about 10 percent or less, whereas a low ash content for metallurgical coal is around 5 percent. In addition, there is nothing extraordinary regarding this ash content figure as the percentage of ash in coal can be reduced quite significantly during the preparation stage. When large reductions in ash content are attempted, the ultimate preparation plant yield is reduced, making the coal very expensive. Thus, it is not economic to alter coal content by a large degree; the material content of the coal in advance of preparation is more important.

The Crowsnest and Peace River fields are predominantly medium-volatile bituminous coals with good coking characteristics. The other coal fields in the province are primarily of non-coking quality. The coals tend to be relatively high in ash content and low in sulphur and calorific value. The first and last of these three characteristics are not favourable to thermal coal users, especially utilities. Major users have set quality characteristics which must be met by potential exporters. One important feature of these restrictive characteristics is the fuel ratio, equal to the fixed carbon content divided by volatile matter.

As mentioned earlier, the market for metallurgical coal from British Columbia is not limited by quality considerations of the importers. In fact, favourable coking characteristics make the province's coal very desirable on the world market. On the other hand, it may be difficult to market British Columbia thermal coal especially in times of excess world supply as quality restrictions are set by the major importers. The following is an overview of restrictions set by groups within the three major Pacific Rim thermal coal importers. All specifications in Table 1.2 are shown on an 'air-dried' basis except moisture content which is shown 'as received'.

1.3 Coal Mines and Producers

This section provides a brief overview of the various mines--existing, under construction and proposed--in three regions as shown in Figure 1.2.

All current major coal producers in British Columbia are found in the Southeast by Crowsnest Pass. Figure 1.4 details the location of the mines in the region, and Table 1.3 gives an overview. Metallurgical coal, with a production level of 10.8 million tonnes in 1981 and forecast to exceed 15 million tonnes in 1985, by far surpasses thermal coal production which reached a level of 2.1 million tonnes in 1981. Expansion and development is underway to raise production to nearly 4 million tonnes of thermal coal in 1983. Further development is entirely conditional upon market demand and actual production levels may be less than anticipated if contracted shipments continue to be reduced. The sluggish nature of metallurgical coal markets has forced the postponement of two mines in the area. One of these, the Sage Creek Coal Ltd. property, has been revised over to thermal coal production. These mines are described in Table 1.4. Should conditions improve or a switchover to thermal coal production prove feasible, construction could begin almost immediately at both the Sage Creek and Elk River properties pending government approval and permits.

Two mines are currently under construction in the Peace River area of Northeastern British Columbia: the Quintette and Bullmoose mines. An agreement between Quintette

TABLE 1.2

QUALITY SPECIFICATIONS FOR THERMAL COAL USE AS GIVEN BY THREE PACIFIC RIM COUNTRIES

	Calorific Value Min. Kcal/kg	Total Moisture Max. Percent	Ash Max. Percent	Volatile Matter Percent	Fixed Carbon Percent	Sulphur Max. Percent	Fuel Ratio
Japan							
Utilities (Japan Coal Development Corp.)	6 000 (6 200)[a]	10.0	15 - 20.0	30 - 35		1.0	2.3 (2.2)
Cement (Cement Association of Japan)	6 500	8.0 - 12.0[b]	15.0	30 - 35		1.0 - 1.5	2.0
Pulp and Paper (C. Itoh and Co.)	6 200 - 6 700	8.0 - 10.0	17.0			0.6	
Korea							
Utilities (Korea Electric Power Co.)	6 000	8.0	17.0	22 - 36	50 - 60	1.0	
Cement (Daesung Co.)	6 000	10.0	20.0	25 - 40	35 - 45	2.0	
Taiwan							
Utilities (C. Itoh and Co.)	5 900	8.0	20.0	24		1.5 - 2.0	
Cement (C. Itoh and Co.)	5 900	8.0	20.0	29		2.0	

[a]The numbers bracketed are the more restrictive guidelines as set by the Electric Power Development Corporation.

[b]A range is given when specifications vary for particular users represented within a user group, or when conflicting numbers have been reported.

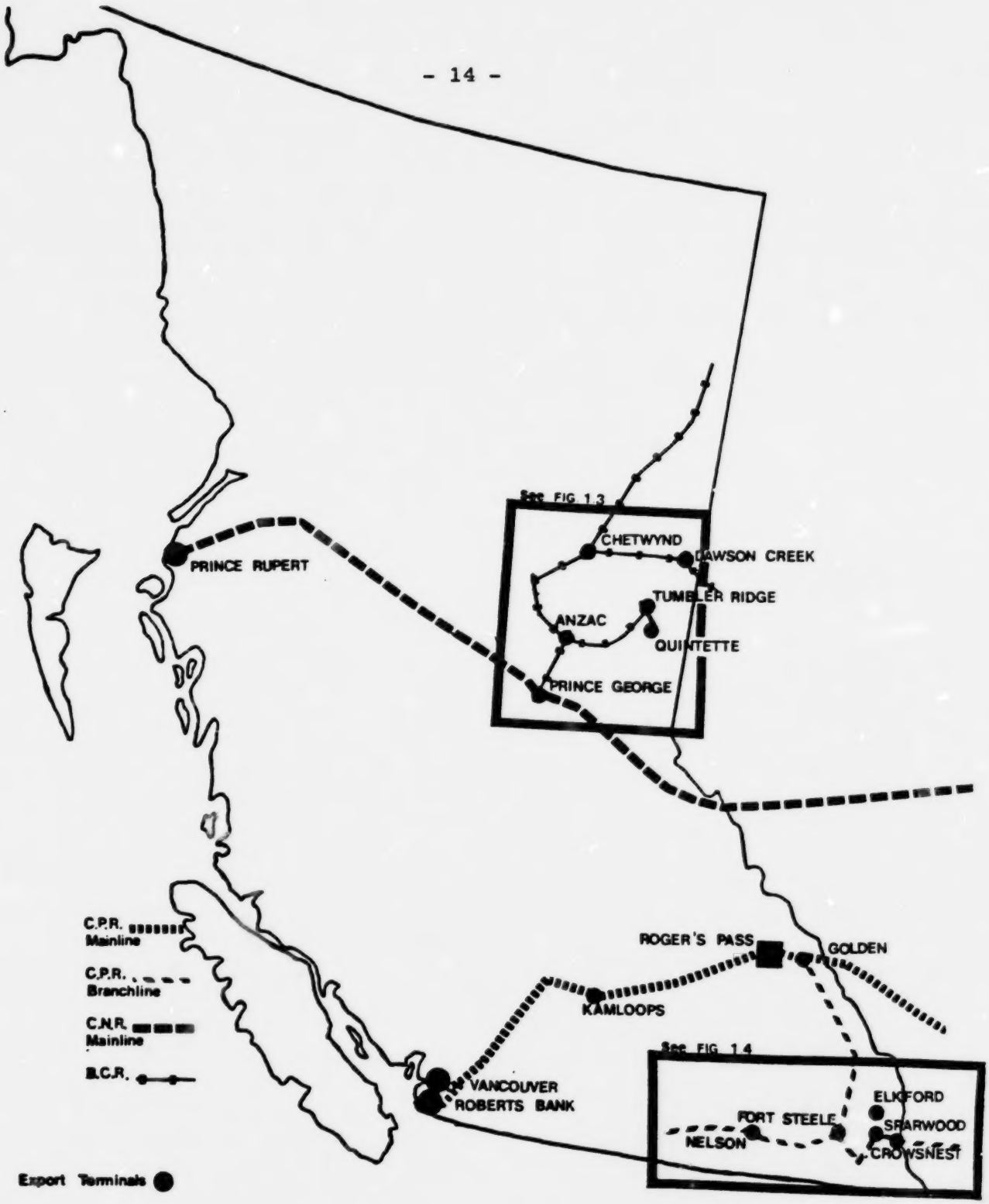

FIGURE 1.2 · BRITISH COLUMBIA COAL REGIONS CURRENTLY UNDER DEVELOPMENT

TABLE 1.3

SOUTHEASTERN BRITISH COLUMBIA PRINCIPAL COAL PRODUCERS
EXISTING MINES[14]

Name of Producer	Area Name and Location	Existing Production (1982)	Brief Description	Primary Markets
BRITISH COLUMBIA COAL LIMITED Owners: BCRIC 67%, Mitsubishi Corp. and a consortium of 9 Japanese steel producers, 33%	Balmer - Harmer Ridge and Michel Mines - Sparwood	7.1 MMt/yr (metallurgical) 0.4 MMt/yr (thermal)	Surface mining accounts for approximately 90% of production. Raw metallurgical coal is processed in a single plant with an approximate capacity of 7.0 million tonnes of clean coal.	Far East - 79% Latin America - 9% Europe - 8% Other - 4%
Joint venture with with Pohang Iron and Steel Company Ltd. of South Korea (POSCO) 20%	Greenhills - Elkford	0.5 MMt/yr (thermal)	The original start-up date of this open pit mine was pushed ahead to August 1982. Initial production rates will be 1.8 million tonnes of metallurgical and 0.5 million tonnes of thermal in 1983. Thermal production will then rise to 1.0 MMt/yr.	-Korea 0.5 MMt/yr (metallurgical) -Contracted metallurgical to Japan, Taiwan and Latin America -Contracted thermal to Korea, Hong Kong and Denmark
BYRON CREEK COLLIERIES LIMITED Owner: Wholly-owned subsidiary of Esso Minerals Canada	Byron Creek - Coal Mountain Mine - Corbin	1.1 MMt/yr (thermal)	This is a surface mine with reserves sufficient to support 3.6 MMt/yr of production. Expansion plans have been instigated and mine capacity should reach 2.0 MMt/yr by late 1983.	-Currently ships to Ontario, Manitoba and Japan -Has a new contract to begin shipments to Hong Kong -Prospect of further Pacific Rim markets
CROWSNEST RESOURCES LTD. Owner: Wholly-owned subsidiary of Shell Canada Resources Ltd.	Line Creek Project - (20 km north of Sparwood)	-No production in 1981 -First shipment of thermal coal February 1982 -First metallurgical coal to be shipped April 1983	The existing development is a surface mine with a capacity of 1.3 MMt of of metallurgical and 1.4 MMt of thermal coal per year. The area properties have a much greater capacity of 5-6 MMt/yr total, but development is conditional upon demand.	-Korea: 3 contracts totalling 1.1 MMt/yr thermal -Japan: contracted 1 MMt/yr metallurgical

TABLE 1.3 (CONTINUED)

Name of Producer	Area Name and Location	Projected Production	Brief Description	Primary Markets
FORDING COAL LIMITED Owners: CP Enterprises 60%, Cominco Ltd., 40% (CP Investments own 54% of Cominco and therefore 81.6% of mine)	Fording River - Fording Mine - 30 km north of Elkford	3.7 MMt/yr (metallurgical)	This surface mine is undergoing a $115 million expansion to increase capacity to 5.0 MMt/yr by 1985. The mine is experiencing a temporary shutdown for the latter part of 1982 due to cutbacks of 35% or so by the Japanese. Sales projections for the year ending March 31, 1983 have been dropped to 3.9 million tonnes.	-Contracts exist with Japan, Korea, Taiwan, Chile and Brazil -Trial shipments have also gone to potential customers in South America and Europe

NOTE: All values are shipment quality coal.

TABLE 1.4

SOUTHEASTERN BRITISH COLUMBIA PRINCIPAL COAL PRODUCERS
PROPOSED MINES

Name of Producer	Area Name and Location	Projected Production	Brief Description
ELCO MINING LIMITED Owners: Subsidiary of six European steel companies: Elk River 50% in a joint venture with the Steel Company of Canada Limited 25%, Home Oil Co. Ltd. 15% and Scurry Rainbow Oil Limited 10% (a subsidiary of Home Oil Co. Ltd.)	Elk River property (49 km north of Elkford)	4.0 MMt/yr (metallurgical)	This project is in the advanced stage of exploration and development. Original plans projected deliveries by 1985, but the sluggish international steel industry has meant slow market development. Subsequently, the earliest shipments which would now be possible would be in the late 1980s. A study of thermal coal potential is now underway.
SAGE CREEK COAL LIMITED Owners: Rio Algom Limited 60% and Pan Ocean Oil Limited 40%	Sage Creek property-- (50 km southeast of Fernie)	2.0 MMt/yr (thermal)	Originally planned as a metallurgical coal mine with a production capacity of 3.0 MMt/yr but required to change to thermal, due to new market conditions. The output levels were also reduced as the result of high infrastructure costs. Trucking was shown to be more economic than the building of a new rail spurline. Sage Creek representatives will soon begin to try to obtain permission to initiate construction with deliveries to come onstream by the mid-1980s.

Coal Limited with the Teck Corporation Ltd. and a consortium of Japanese steel companies started this megaproject in 1981. Table 1.5 and Figure 1.3 present a few details of the mines themselves, but do not reveal the true extent of the project. In addition to the over $1.0 billion (in 'as spent' Canadian dollars) to be made in capital expenditures on the mines, money will be spent on the new town of Tumbler Ridge, and numerous infrastructure developments such as a new 129-kilometre rail spurline, upgrading of the CNR mainline, and a new coal terminal on Ridley Island. Total capital expenditures by both government and industry in the project will be very close to three billion Canadian dollars as spent over the entire construction periods.[13] Although the combined magnitude of production of the two mines is substantial, about 98 percent of reserves in the area would still be untapped at the end of a twenty-year production period. There are numerous other owners of coal properties investigating northeast mine development, especially in view of the fact that most of the infrastr cture would already be in place, reducing a major cost component of development. Table 1.6 lists the proposed northeastern mines. It should be noted that of a total of sixteen projects under consideration, only two were near the construction phase in 1982 and one of these, the Sukunka mine, has subsequently been cancelled.

There is a negative aspect to the Northeast Development which is often ignored. Under market conditions which are less than favourable, a mega-project is being developed where infrastructure costs are incredibly high. A new town, roads, a rail line and two mines are all emerging in an undeveloped area in the far north of British Columbia. Further development and expansion could have been undertaken in Southeastern B.C. where infrastructure is well established and less expensive to expand. No major new town would have been required, unemployed, experienced personnel reside in the area and significant reserves are as of yet untapped. In addition, as coal exporting countries compete for limited import markets, so will Northeast B.C. producers be competing against Southeast B.C. producers for a portion of the Canadian market share. This means favourable market conditions for importers of British Columbia coal, in fact it was the Japanese who pressed for the development of a new source of Canadian coal. Japanese importers had threatened not to expand their contractual committments with existing

TABLE 1.5

NORTHEASTERN BRITISH COLUMBIA PRINCIPAL COAL PRODUCERS
MINES UNDER CONSTRUCTION

Name of Producer	Area Name and Location	Projected Production	Brief Description	Primary Markets
QUINTETTE COAL LIMITED Owners: Denison Mines Limited 46%, Mitsui Mining 21%, Tokyo-Boeki 21%, and Charbonnages de France 12%	Quintette - Tumbler Ridge (100 km southwest of Dawson Creek)	5.0 MMt/yr (metallurgical) 1.5 MMt/yr (thermal)	The project involves two open pit mines with initial deliveries to begin in early 1984. Total capital costs over a 20-year production period are $924 million (current Cdn.$).	Japan: contracts with steel companies for 6.3 MMt/yr over 15 years with an option for 5 more years.
TECK CORPORATION LIMITED	Bullmoose - Tumbler Ridge (80 km southwest of Dawson Creek)	2.3 MMt/yr (metallurgical)	This is also an open pit mining operation to begin deliveries early in 1984. Capital cost of the project is $172 million (current Cdn.$) over a 20-year production span.	Japan: contract for 1.7 MMt/yr was finalized in 1981 although buyer has yet to be found for the remaining 0.6 MMt/yr of production.
DAVID COAL CORPORATION Owner: David Minerals Ltd. 85% and Ssangyong Corporation 15%	Willow Creek (38 km west of Chetwynd)	0.6 MMt/yr (thermal)	Agreement has been reached with Ssangyong Corp. of South Korea to take 0.4 MMt/yr of. Options are available to expand this contract to 0.6 MMt/yr. Production is planned for 1983.	

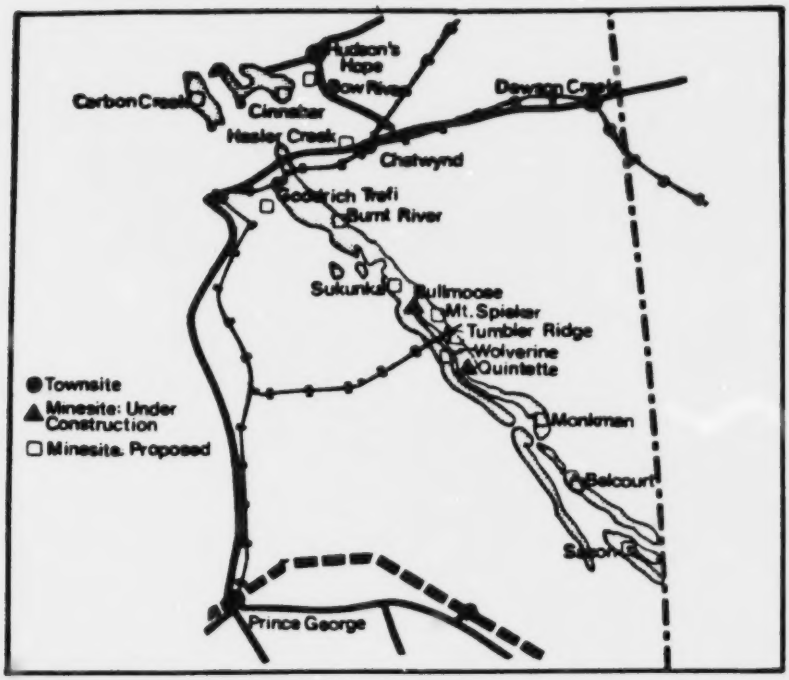

FIGURE 1.3: COAL PROPERTIES UNDER DEVELOPMENT AND PROPOSED IN THE NORTHEAST

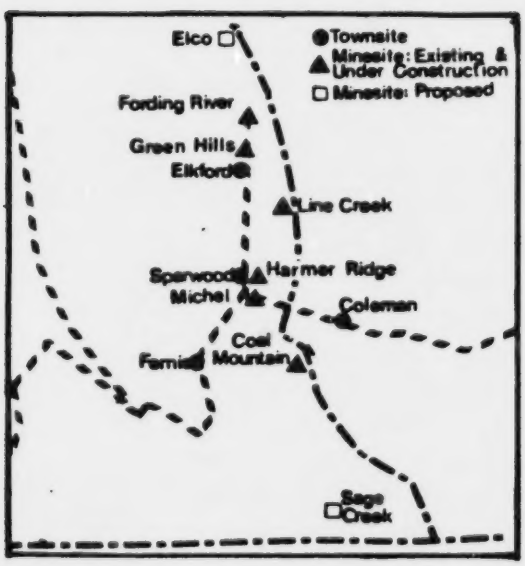

FIGURE 1.4: EXISTING COAL MINES

Source: Mining Magazine-July 1982 and Coal Miner 1982 Issues

TABLE 1.6

NORTHEASTERN BRITISH COLUMBIA PRINCIPAL COAL PRODUCERS
PROPOSED MINES

Name of Producer	Area Name and Location	Projected Production	Brief Description
PETRO-CANADA LTD. Owners: Petro-Canada 50%, Canadian Superior Oil Ltd. 33% and McIntyre Mines Limited 17%	Monkman (120 km southwest of Dawson Creek	3.3 MMt/yr (metallurgical) 1.0 MMt/yr (thermal)	To date, about $16.0 million has been spent on exploration, environmental, and feasibility projects. Petro-Canada officials still anticipate a 1985 start-up date for the mine although no firm contracts have been made for the forecast production. A more realistic start-up would be in 1988. The period of production for the two open pit mines at capacity will be 16 years. This is the most imminent of the proposed northeast projects and will be the third developing mine if markets can be found.
BRITISH PETROLEUM INCORPORATED Owners: BP Canada Limited 87.5 % and Brameda 12.5 %	Sukunka (55 km south of Chetwynd	-1.0 MMt/yr (metallurgical initially) -3.0 MMt/yr (metallurgical ultimately) -Thermal potential	This $200 million underground mining project has been cancelled due to a soft coal market and a limited company cash flow due to the federal government's National Energy Program. One other major problem associated with Sukunka location was the fact that the Tumbler Ridge--British Columbia Railways spurline could not be extended to this mine due to engineering handicaps. Prior to cancellation, $46 million had already been invested and a major buyer in Ssangyong Cement Corporation of South Korea was found, although sales were not sufficient for development.
RANGER OIL LIMITED Owner: Teck Corp. under option to Ranger	Mt. Spieker - Tumbler Ridge (100 km southwest of Dawson Creek)	1.5 MMt/yr (metallurgical)	Production would be from both open pit and underground mines. Exploration and market search is underway although budgeting was low for 1982 due to soft coal markets.
SAXON COAL LIMITED Owner: Wholly owned subsidiary of Denison Mines Ltd.	Saxon (160 km south of Dawson Creek, adjacent to Alberta border)	4.0 MMt/yr (metallurgical)	A detailed feasibility study has been completed although no plans for development have been made. Production would be from open pit and underground operations.

TABLE 1.6 (CONTINUED)

Name of Producer	Area Name and Location	Projected Production	Brief Description
BELCOURT CANADA LIMITED Owners: Gulf Canada Resources 50% and Denison Mines 50%	Belcourt (140 km south of Dawson Creek, adjacent to Alberta border)	4.0 MMt/yr (metallurgical) 0.8 MMt/yr (thermal)	A five-year detailed export and feasibility program has been completed. Production would be from both open pit and underground mines.
CINNABAR PEAK MINES LIMITED	Cinnabar (20 km southwest of Hudson's Hope)	0.5 MMt/yr (thermal initially) 2.0 MMt/yr (thermal)	Stage I feasibility study has been completed and production could begin in 1983 if thermal coal samples sent to Japan precipitate contracts. Although initial production would be from a shallow open-pit thermal mine, underground reserves of metallurgical could also be produced.
UTAH MINES LIMITED	Carbon Creek (20 km west of Bennett Dam)	2.5 MMt/yr (thermal)	Exploration stage has been completed and feasibility stage is underway. The coal is accessible through surface mining for 80% of reserves.
TECK CORPORATION LIMITED	Burnt River (57 km southwest of Chetwynd	1.0 MMt/yr (thermal)	Exploration stage has been completed revealing that the coal is close to anthracite classification. The project has Stage I, B.C. government approval.

NOTE: There are seven other properties currently under investigation for development. All are at the exploration stage. The projects and their owners are as follows:

1. Wolverine (Dupont of Canada)
2. Goodrich (Gulf Canada Resources Incorporated)
3. Trefi (Gulf Canada Resources Incorporated)
4. Wapiti (Gulf Canada Resources Incorporated)
5. Hasler Creek (Pan Ocean Limited)
6. Pine Pass (Shell Canada)
7. Bow River (Utah Mines Limited)

B.C. producers to meet projected requirements, but to obtain these supplies from Australia should no new British Columbia coal region be developed. It is uncertain whether these threats would have been carried out, but hindsight suggests that the additional demand would most likely have been split between Australian and Southeast B.C. producers. Unfortunately, this gives the traditional source of supply, the Southeast, an additional marketing burden.

The third area under consideration is located in the Westcoast Region on Vancouver Island. The Quinsam Project is in the final preparatory stages, and pending government approval, construction is projected to begin in 1983. Environmental considerations appear to be the main roadblock to development. Table 1.7 holds a brief description of the project.

TABLE 1.7

COASTAL BRITISH COLUMBIA PRINCIPAL COAL PRODUCERS
PROPOSED MINES

Name of Producer	Area Name and Location	Projected Production	Brief Description
QUINSAM COAL LIMITED **Owners: Brinco Mining Ltd. 50% and Weldwood of Canada Ltd. 50%**	Quinsam Coal Project (27 km from Campbell River)	1.0 MMt/yr (thermal)	This surface mine is in the final stages of environmental study and has just received B.C. government stage II approval. Construction is anticipated to begin by 1983. Deliveries are slated to begin in 1985 and to continue over a thirty year period. The mine is located only twenty miles to tidewater so infrastructure costs are virtually non-existent when compared with northeastern B.C. coal development.

Footnotes

[1]These numbers were received from the Coal Resources Division, Energy, Mines and Petroleum Resources, British Columbia, and will be published later this year.

[2]See Energy, Mines and Resources Canada, Coal Resources and Reserves of Canada, Report ER 79-9 (Ottawa: Supply and Services Canada, December 1979).

[3]A coal field is a geographic area or geological formation of coal usually containing many deposits. A coal deposit is a discrete body of coal within a field.

[4]Sources for all specifications which follow are: Opportunities for Coal Liquefaction Research in British Columbia, by Swan Wooster Engineering and Others, prepared for the B.C. Science Council in May 1980; 1981 Keystone Coal Industry Manual (New York: McGraw-Hill Mining Publications, 1981); and industry sources.

[5]By removing moisture through drying, the other components of the coal are enriched: the volatiles, ash and fixed carbon levels are increased. The numbers shown were received from the Coal Resources Division, Energy, Mines and Petroleum Resources, British Columbia, and were dated to 1979. 'As received basis' means that no drying of the coal has occurred; the coal is basically run-of-mine.

[6]Obtained from the Coal Resources Division, Energy, Mines and Petroleum Resources, British Columbia.

[7]See Chapter 3 of this paper for an in-depth description of the Crowsnest Pass Agreement.

[8]Canada, Energy, Mines and Resources, An Energy Policy for Canada - Phase I. Volume II, Appendices (Ottawa: Information Canada, 1973), pp. 285-288. Here, statistics are given in long tons as opposed to metric tonnes although the numbers are very similar.

[9]Obtained from the Coal Resources Division, Energy, Mines and Petroleum Resources British Columbia.

[10]Ibid.

[11]Ibid.

[12]Information was received from contacts within Industry, Trade and Commerce Canada.

[13]See Canada Department of Regional Expansion, A Benefit-Cost Analysis of the North East Coal Development (Victoria, July 1982); and Price Waterhouse Associates, Quintette Coal Ltd., Teck Corporation. The North-East Coal Project (Vancouver: Price Waterhouse Associates, April 1981).

[14]Sources for all the tables on existing and potential producers are varied and include Robinson, Dames and Moore, Canadian Coal Industry Report 1980 (Toronto: Northern Miner Press Ltd., 1980); Mining Magazine and The Coal Miner, in addition to industry sources.

Chapter 2

EXPORT MARKETS FOR BRITISH COLUMBIA COAL

Although Japan offers the largest market for Canadian coal, it is by no means the sole export destination. Coal from British Columbia reaches many parts of the world as shown in Table 2.1. The following sections profile coal markets in three geographical areas: Western Europe, Latin America (including Mexico) and Asia. Occasionally it is difficult to differentiate between coal imported from British Columbia and from Canada as a whole, and every effort will be made to show the B.C. contribution.

2.1 Western Europe: Thermal Coal

Indigenous coal production has actually decreased in Western Europe in recent years. Output in 1981 was 245 million tonnes, 25 MMT less than 1973 levels.[1] The high production cost associated with underground mining at increasing depths, combined with the low relative price of imported coal, indicates that imports will represent an increasing share of coal consumed in the European Economic Community (EEC). Security of supply and domestic employment considerations have motivated Community governments to continue to subsidize production from unprofitable mines. Average costs of production in the first half of 1981 ranged from $91.40 (U.S.) per tonne in the United Kingdom to as high as $119.97 (U.S.) per tonne in Belgium. Approximately 500,000 jobs within the community are directly associated with coal mining, while another 500,000 people are employed in transport, equipment manufacture, processing, and other related industries.[2]

As a single entity the community is the largest importer of oil in the world and like, other nations, the EEC is attempting to reduce dependence on oil. New and renewable resources such as biomass and hydroelectricity, offer a limited potential as alternatives. The former requires further investment in research and development, while the

TABLE 2.1

BRITISH COLUMBIA COAL EXPORTS - DISPOSITION
(000's tonnes)

	British Columbia		
	1980	1981	1982
(1) Hong Kong	-	-	177
Japan	7 669	7 460	6 622
Pakistan	24	105	147
South Korea	980	1 696	1 995
Taiwan	211	275	520
TOTAL ASIA	8 884	9 536	9 461
(2) Belgium/Luxemburg	-	56	-
Denmark	252	319	330
Greece	258	-	-
Netherlands	42	-	-
Spain	48	54	-
Sweden	84	164	-
TOTAL W. EUROPE	684	593	330
(3) Brazil	289	463	-
Chile	134	248	51
Mexico	29	219	33
TOTAL LATIN AMERICA	452	930	83
(4) United States	1	68	67
TOTAL EXPORTS	10 021	11 127	9 941

SOURCE: Statistics Canada Catalogue 45-002, Coal and Coke Statistics, December 1982, 1981 and 1980.

latter is already exploited to near maximum levels. In the case of electricity generation, nuclear and coal generation are the most viable alternatives. The EEC estimates that by 1990, nuclear and coal will fuel 80 percent of electricity generation, with coal accounting for 43 percent. Coal penetration will actually decrease over time as a proportion of total generation, but the absolute quantity of coal required will increase as energy requirements expand. The Commission of the European Communities has set a proposition before the EEC to expand coal use due to uncertainties attached to the future of nuclear power and constraints on the contribution of natural gas.[3] Should this resolution be passed by the members of EEC, the forecast for coal consumption presented in Table 2.2 is representative of the likely upper limit of the EEC demand forecast.

TABLE 2.2

FORECAST COAL CONSUMPTION-EEC

	1980		1990		2000	
	million tonnes	%	million tonnes	%	million tonnes	%
Electricity Generation	184	58.6	220	61.1	320	64.0
Inputs to coke-ovens	88	28.0	90	25.0	95	19.0
General industry	14	4.5	25	7.0	55	11.0
Domestic and other (including gasification and liquefaction)	25	8.9	25	7.0	30	6.0
Total	314	100.0	360	100.0	500	100.0

SOURCE: Official Journal of the European Communities, C105, Volume 25, 16 April, 1982.

The underlying assumptions of this forecast are: average annual economic growth of 2.5 percent and increases in electricity consumption of 3.5 percent per annum.

In order to maintain security of supply when demand necessitates the import of coal, members of the EEC are

desirous of diversificating their sources and long-term commitments. Imports to the Community were about 70 million tonnes in 1982. The United States is the largest supplier, and imports from that nation represented about half of the total. Canada increased its sales into most member countries between 1980 and 1981. The only exception was sales to the Netherlands which decreased. A trial shipment to Greece in 1980 did not precipitate any future contracts. In 1981 European importers had to seek new suppliers to replace coal from Poland, where the country was in upheaval and little coal produced, and from Australia, where labour strikes had curtailed production. Although both countries have returned to pre-1981 output levels, there is some indication that the security represented by Canadian supply may encourage the EEC to continue importing Canadian coal. Despite this possibility, Canada is not and will not be a major force in the Community coal market in the foreseeable future due to price and quality advantages of alternative import suppliers. A brief overview of the likely Western European destinations is provided below.

2.1.1 Denmark

Despite extensive oil and gas discoveries in the North Sea that have improved the Danish energy situation, coal imports are still required. British Columbia thermal coal exports to Denmark amounted to 330 000 tonnes in 1982. Although this country is the province's major coal consumer in the Community, this amount represents about 3 percent of total British Columbia exports for that year.

2.1.2 Federal Republic of Germany

West Germany is the largest coal producer in the EEC. Much of this output is very expensive, but the government subsidizes the industry to the extent that output levels will be maintained for the remainder of this century. Import quotas are in place as domestic coal is given absolute priority. This is Canada's largest market in Western Europe, with market penetration at about 7 percent of total imports, but currently, none of these thermal coal exports originate in British Columbia.

2.1.3 Italy

If Italian demand forecasts are accurate, Italy will increase coal consumption by the greatest amount of all EEC members, overtaking France as the Community's largest importer. Canadian exporters (British Columbia producers to a lesser extent) have maintained steady coal trading relationships with Italy over the past few years and this trend should continue. Thermal coal will account for a much larger component of potential Italian import requirements.

2.1.4 Sweden

Sweden is also a likely importer of British Columbia coal. Here again, North Sea production will reduce coal requirements during this century. British Columbia exports have been received with regularity over the years and are expected to maintain their market share.

Of the 1 398 000 tonnes of Canadian coal exported to Europe in 1981, the portion originating in British Columbia represented some 42 percent, or 592 598 tonnes. The trend emerging in 1982 is a shift from west coast to east coast exports. Nova Scotia coal is being exported to a large degree, and British Columbia exports are down to 20 percent of the Canadian total in 1982. Also, Europe is experiencing a glut of coal, where storage areas are overflowing with stock. Under these circumstances, the growth of British Columbia exports to the region may be minimal to 1985 but the potential exists for large increases by 1990. As a proportion of current export levels, the increase is likely to be substantial but the absolute quantities will still be small relative to other markets. All exports will be to thermal coal users, the bulk of which will accrue to Danish and Swedish markets. One recent transaction is indicative of this trend. B.C. Coal Ltd. signed a ten-year contract with Elkraft Power Company of Copenhagen in 1982. Thermal coal will come from the Balmer and Greenhills mines in Southeastern British Columbia, for a total of 3.8 million tonnes over the contract period.

Due to the recent economic downturn, steel production in Europe has not been growing as previously anticipated.

This directly affects the amount of coking coal required, and hence the demand for this form of coal is forecast to grow quite slowly to 1990. United States Appalachian metallurgical coal will continue to enjoy both cost and quality advantages over Western Canadian coal in supplying the steel industry, so no British Columbia exports are assumed to be supplied to this market in the forecast period.

Exports of coal to the Community from British Columbia were 0.33 million tonnes in 1982. Estimated figures for 1985 and 1990 are 1.5 to 2.5 and 2.5 to 4.5 million tonnes, respectively.

2.2 Latin America: Metallurgical Coal

It is in the developing nations where energy demand and hence the demand for thermal coal, is escalating. Industrialization and economic growth do generate greater energy demand. The relatively high cost of oil in the long-term and the dependency resulting from large import expenditures, encourage the promotion of indigenous energy supplies. Indigenous thermal coal supplies are sufficient to meet projected domestic requirements. The metallurgical coal market, on the other hand, presents opportunities for British Columbia producers. Contracts with Brazil, Chile and Mexico reached almost one million tonnes in 1981. The following countries represent the most likely future markets.

2.2.1 Brazil

Brazil has substantial coal reserves and extensive exploration is currently underway that may add to the total. Quality is generally very poor, but domestic demand for thermal coal can be met completely by local supplies until at least 1985. Significant growth in demand combined with a poor realization of exploration efforts, may result in small import requirements of thermal coal by 1990.

The situation is somewhat different regarding metallurgical coal. Indigenous reserves are insufficient to support steelmaking requirements. Imports in 1981 were approximately 4.9 million tonnes, of which about 9.5 percent or 463 000 tonnes were supplied by British Columbia mines.

Diversification of sources of coking coal has been, and will continue to be, a major policy of the Brazilian national steel company, Companhia Siderurgica Nacional (SIDERBRAS). Suppliers include Australia, Canada and Poland, although the bulk of coal imports have historically originated in the U.S.; the country's only outside supplier during the early 1970s.

SIDERBRAS estimates that import requirements will rise to 10.0 million tonnes by mid-1980, with Canada maintaining a market share of approximately 14 percent.[5] This will constitute an anticipated 1.3 to 1.5 million tonnes to be exported from British Columbia to Brazil in 1985. Steel production is forecast to continue to rise, as Brazilian steel consumption levels per capita are still far below those of more developed countries. If Canada can maintain its projected market share to the end of the decade, exports could rise to about 2.0 million tonnes or more by 1990.

2.2.2 Chile

Chile's coal reserves are extensive, but located in a remote area lacking infrastructure. Some reserves are as far as 2500 kilometres from markets. Current government policy is laissez-faire in attitude, and further development of reserves would require government input to improve infrastructure. Thermal coal demand is not substantial, estimated at 1.1 million tonnes in 1982. Domestic supplies are sufficient to meet most of this demand, with the U.S. supplying the remainder.

British Columbia is established as a major supplier of metallurgical coal to Chile. Over 50 000 tonnes were exported in 1982. Fording Coal has recently concluded an eight-year contract to supply coking coal at the rate of 150 000 to 200 000 tonnes per annum. Exports are expected to continue through 1990, albeit at rates commensurate with a minimal projected increase in demand over the period. Export levels of about 400 000 tonnes in 1985 and 600 000 in 1990 are forecast.

2.2.3 Mexico

Mexico has a variety of energy resources including coal, petroleum and natural gas. Petroleum reserves are extensive, and Mexican industry relies on this source for the bulk of its needs. Known thermal coal reserves are quite small, but the scope of resources indicates that, with further exploration efforts, reserves can be expanded to meet projected domestic requirements.

Metallurgical coal is imported, and about 200 000 tonnes originated in British Columbia during 1981. Due to the proximity of Canada's west coast coal deposits, it is anticipated that British Columbia coal will continue to meet a portion of Mexican requirements. Export levels were not very large in 1982 (about 30 000 tonnes), as demand is down significantly from 1981. Coal from British Columbia will continue to reach the Mexican market in 1985 and 1990, but demand is expected to remain fairly low.

2.3 Asia: Thermal and Metallurgical Coal

Given the large area that is under consideration here, one would anticipate a variety of markets in Asia for British Columbia coal. In reality, three countries--Korea, Taiwan and Japan--accounted for almost 100 percent of total 1982 import demand. Other countries in the region require small tonnages annually, but many long-term contracts have already been concluded with non-Canadian suppliers. Such is the case in the Philippines, where Australian producers who supplied the bulk of the 500 000 tonnes required in 1982, have commitments well into the 1990s. British Columbia producers, among them Sage Creek Coal Ltd., are among a large group of companies offering to cover the remaining demand.

Apart from Hong Kong and the other three main importers mentioned earlier, it appears that the most likely destinations for British Columbia coal will be Pakistan and India. Exports of metallurgical coal to Pakistan were over 100 000 tonnes in 1981, and rose to about 150 000 tonnes in 1982. Based on the favourable trade relationship existing between Alberta coal producers and Indian importers, there is a good potential for imports from British Columbia as well. It is

difficult to estimate the extent of Canadian penetration into the Asian coal market. Consequently, the discussion below is limited to those countries which are going to be the prime British Columbia coal export destinations, and for which information is readily available. An analysis of potential Japanese demand concludes this section, as the market is both the largest and most complex.

2.3.1 Hong Kong: Thermal Coal

Up until the 1980s, no coal was used by this British colony. Expansion of existing electrical generating plants and the building of a new plant have led to the use of coal in dual-fired units which can accept either oil or coal. The China Light and Power Company Ltd. (CLPC) is the largest of Hong Kong's two major electric utilities. Canadian commitments with CLPC include a B.C. Coal Ltd. contract to supply 1.57 million tonnes over six years to a partially owned subsidiary of CLPC, Kowloon Electric Supply Co. Ltd. It is no small feat which British Columbia producers have achieved by making significant inroads into the Hong Kong market. Chinese coal reserves are a more accessible (by virtue of distance transported) supply source. A mutually advantageous trade arrangement exists whereby CLPC imports much of its coal from China, exporting in return over one million kilowatt hours of electricity per day. In other areas of thermal coal demand, Byron Creek Collieries Ltd. has recently obtained a 100 000 tonne per year, five-year contract to supply China Cement of Hong Kong.

In addition to Canadian and Chinese coal, imports are contracted from Australian and South African sources, so there appears to be very little uncommitted demand for thermal coal to 1990. British Columbia producers are anticipated to meet about 600 000 tonnes of this demand in 1985 and about 1.5 million tonnes by 1990.

2.3.2 Korea: Thermal and Metallurgical Coal

The Republic of Korea has significant reserves of anthracite, but no other forms of coal and hence must import most of its supply. An extensive trade network has developed with Canada and the outlook for expanded coal trade is very

favourable. In 1982, the Republic of Korea was the second largest importer of British Columbia coal, second only to Japan. The Korean government is giving financial encouragement to Korean companies interested in joint ventures with coal producers.

One such venture with a British Columbia firm is that between the David Coal Corporation and the cement firm Ssangyong Corporation of South Korea for the development of property in Northeastern British Columbia. The minimum terms of export are 400 000 tonnes per annum for nine years. Ssangyong Corporation is also committed to buy 350 000 tonnes per year over ten years from Crowsnest Resources' Line Creek mine.

The Korea Electric Company (KECO) is a government-controlled body and the only power company to be importing thermal coal. There are two major power plant complexes with initial phases to be coming onstream before 1985: the Samcheonpo and Gojeong plants. The massive coal commitments to be dedicated to these enterprises--two to three million tonnes per year for the Samcheonpo plant alone--has opened up a large new market for thermal coal exporters. British Columbia producers have acquired major contracts with KECO to supply a portion of the requirements. Crowsnest Resources is committed to supply 750 000 tonnes per year starting in 1983, and Fording Coal will ship 200 000 tonnes per annum, also beginning in 1983.

Of total thermal coal imports to South Korea in 1982, Canada contributed about 14 percent. Contracted thermal coal commitments with British Columbia producers through to 1990 represent tonnages closer to 20 percent of forecast demand. These thermal exports are estimated to be about 1.9 million tonnes in 1985 and 2.5 million tonnes in 1990.

There is only one consumer of coking coal in Korea, Pohang Iron and Steel Company (POSCO). POSCO has contributed $26 million (Canadian) to gain a 20 percent interest in the new B.C. Coal Ltd.'s Greenhills mine in Southeastern British Columbia. As a result, B.C. Coal Ltd. has obtained a 20-year, 500 000 tonne per year contract to supply POSCO beginning in 1983. Steel production increases anticipated by

POSCO during the 1980s will mean further metallurgical coal requirements not currently covered by British Columbia producers.

British Columbia will supply some 28 percent of the metallurgical coal required by POSCO in 1982. The keys to maintaining this significant market share are competitive price and stable supply.

Purchase forecasts completed by the steel company estimate Canadian supply to rise at an annual rate of about 7.0 percent.[6] Total Canadian sales to POSCO are estimated to be 2.1 million tonnes in 1985, increasing to 3.4 million tonnes by 1990.[7]

2.3.3 Taiwan: Thermal and Metallurgical Coal

Indigenous coal production declined from an historic average of about 3.0 million tonnes per year. The reduction is due to high mining costs associated with thin, deep coal seams. Domestic coal production will be held at its current maximum capacity of 2.6 MMt per year, hence imports will rise to compensate for the decline and to meet expanded requirements.

Indigenous coal quantities have been sufficient to meet domestic thermal demand until fairly recently. Conversions from oil to coal generating stations, combined with declining coal production, has resulted in the emergence of a large market for imported thermal coal. Oil contributed 52 percent of total energy input for electricity generation by the Taiwan Power Corporation in 1981. Coal's contribution was only 11 percent at the time. Off-oil programs imply a rise in coal input to 32 percent while oil will decline to 22 percent by 1985. Nuclear power will become the reigning energy source for electricity generation, at 37 percent in 1990, but coal will be vying for the lead at 36 percent in that year.

If Canada can penetrate the Taiwanese thermal coal market to the same extent as in Korea, say to about 14 percent of forecast requirements, then representative export estimates would be about 1.0 million tonnes in 1985 and

2.0 million tonnes in 1990. Although Alberta exports have been minimal to date, producers there are expected to compete vigorously with those in British Columbia for this market. This being the case, the B.C. market share is forecast to be about 0.8 million tonnes in 1985 and 1.3 million tonnes in 1990.

British Columbia coal producers currently supply substantial quantities of metallurgical coal to the China Steel Corporation of Taiwan. Fording Coal Ltd. has a ten-year, 350 000 tonne per year contract to sell coking coal from its Elkford mine, and is currently the steelmaker's largest supplier. B.C. Coal Ltd., is emerging as a major competitor having contracted to sell 250 000 tonnes from its Sparwood mine to China Steel over the period from mid-1982 mid-1984. Agreement has also been reached on a further 200 000 tonnes from mid-1983 for one year, increasing to 300 000 tonnes annually to 1992.

Metallurgical coal exports from British Columbia to Taiwan will continue to contribute significantly as steel-making in this developing nation will continue a gradual expansion. At the lower end of the scale, projected exports of metallurgical coal to Taiwan from British Columbia will be 1.0 million tonnes in 1985 and 1.5 million tonnes in 1990. This is a conservative estimate, and it could be increased substantially should market penetration increase or steel production rise.

2.3.4 Japan: Thermal and Metallurgical Coal

Japanese domestic reserves of coal are neither of high quality nor substantial quantity. Government heavily subsidizes the industry in order that some portion of requirements are met by domestic sources. Production has dropped at a rate of 4.2 percent per annum over the period from 1973 to 1979, but current levels of 7.0 million tonnes of coking coal and 11.7 million tonnes of thermal coal are expected to be maintained until scarcity necessitates cutbacks.[8]

Until the late 1970s, Japanese thermal production was sufficient to meet demand, but since that time, imports have

begun to escalate. Table 2.3 shows Japanese coal imports; in 1981 thermal coal represented almost 15 percent of total coal imports. There are two major consumers of thermal coal in Japan: the electric utilities and cement producers.

TABLE 2.3

1981 COAL CONTRACTED IMPORTS - JAPAN
(000's tonnes)

From	Coking	Thermal	Total	% of Total
Australia	32 420	7 283	39 703	44.6
U.S.A.	28 472	2 119	30 591	34.4
Canada	10 624	1 275	11 899	13.4
South Africa	2 850	1 020	3 870	4.4
China	1 500	1 165	2 665	3.0
USSR	-	50	50	-
Other	150	-	150	-
Total	76 016	12 912	88 928	100

SOURCE: The Tex Report Ltd., Coal Manual 1982 (Tokyo: Tex Report Ltd. 1982), pp. 95 and 415.

There are two main coal consuming power companies in Japan: Hokkaido Electric Power Company Ltd. (Hokkaido Electric) and the Electric Power Development Company Ltd. (EPDC). The latter is majority-owned by the government and was formed in 1952 to handle exceptional projects. Combined demand by these two companies was about 10.5 million tonnes of coal in 1982.[9] EPDC has obtained approval for three new coal-fired units, while four other units are planned for the mid-1990s. Approval must be given by the Electric Power Development Co-ordination Council in order for projects to be considered for construction. Hokkaido Electric has won approval for two units and another two are under consideration. Should all five approved units proceed on schedule, 1985 thermal demand by the two companies will be 2.8 million tonnes greater than in 1982, and total 14.0 million tonnes by 1990. As with other utilities, these two companies are required to aid the domestic coal industry which supplied about two-thirds of total 1982 demand. The ratio of domestic versus import

supply may reverse as early as 1990 if approved projects proceed on schedule. These figures are shown in Table 2.4.

TABLE 2.4

TOTAL ESTIMATED DEMAND FOR THERMAL COAL BY ELECTRIC UTILITIES - JAPAN
(000's tonnes)

	1982	1985	1990
Total (approved projects)	13 541	22 340	27 680
Imports	4 500	13 040	18 320
Imports as % of Total	33.2	58.4	66.2
Total (all projected projects)	13 541	25 640	50 880

SOURCE: C. Itoh and Co. Ltd., "Market Report on Coking and Steaming Coal," January 1982.

It should be noted that the last row of Table 2.4 includes the import demand which would arise if all of the thirty or more 'planned' thermal coal generating projects came onstream as scheduled.

Although it is government policy to encourage coal use by utilities, nuclear generation will still be the most important source of energy for power generation in Japan in the future. Combining this with a demand forecast conducted by the electric utilities in the Spring of 1982, which revised 1981 demand projections downwards by 10 percent, it is reasonable to consider only approved projects when estimating 1985 coal demand. Many projects have already been postponed, and any significant rise in demand as a result of currently unapproved projects coming onstream would not occur until the 1990s.

Where will all this thermal coal originate? The electric utilities have set guidelines wherein they desire 25 to 40 percent of imported coal to originate in North America.[10] It is stressed that this North American supply is not a fixed proportion, only to be realized if North American price is competitive with alternative sources.

If the minimum contribution set out in the guidelines is achieved, Canadian and U.S. suppliers will export approximately 3.3 million tonnes to the Japanese electricity industry in 1985 and 4.6 million tonnes in 1990.

United States suppliers have historically exported double the Canadian tonnage of thermal coal to Japan and are expected to maintain this ratio. Little room remains for new contracts between British Columbia producers and Japanese electric utilities to 1985 during which time only approved project demand is considered. There exists a potential for increased exports in 1990, even with the low demand forecast in Table 2.4. Adhering to the given range of 25 to 40 percent of total imports to originate from North America, Japanese utilities could require between 4.6 and 7.4 million tonnes of thermal coal for approved power plant conversions and construction in 1990. If the coal demands of projects under consideration are added to the 1990 figures given above, North American potential sales rise to between 12.7 and 20.4 million tonnes for 1990. Forecasts, such as those done by the Chase Manhattan Bank, do suggest high import levels. Chase's best estimate forecasts total Japanese demand for thermal coal for electricity generation at 38 MMt in 1990.[11] This estimate, however, was released in 1981, when inflated rates of projected demand were the norm.

Coal was used by the Japanese cement industry until the 1960s at which time conversion to oil occurred to the extent that oil eventually accounted for 95 percent of fuel consumed in firing. This situation was reversed during 1980 and 1981, and conversions to coal have now reached 90 of each 100 kilns. Although significant, demand for thermal coal in the cement industry is less than that required for electricity generation. Canadian suppliers have met some portion of this demand, as seen in Table 2.5.

TABLE 2.5

JAPANESE THERMAL COAL IMPORT CONTRACTS FOR THE CEMENT INDUSTRY - 1981
(million tonnes)

Country of Origin	Million Tonnes
Australia	5.91
U.S.	1.64
Canada	1.17
China	0.47
South Africa	0.25
USSR	0.05
Total	9.49
Indigenous	2.70

SOURCE: C. Itoh and Co. Ltd., "Market Report on Coking and Steaming Coal," January 1982 and The Tex Report Ltd., Coal Manual 1982.

As conversions are now almost complete, there will be no additional demand generated from that segment of the industry. The only factor contributing to further increases in coal demand in this sector would be increased cement production. Currently, clinker production is declining.

Existing contracts with exporting countries should be sufficient to meet requirements to the end of the decade. Canadian contracts have been concluded in 1982 with Luscar Sterco Ltd. which supplies coal from its Alberta Coal Valley Mine, and with Byron Creek Collieries for 200 000 tonnes from the Coal Mountain Mine in Southeastern British Columbia. As coal demand is forecast to remain constant, or even fall, during the period to 1985, only those suppliers under long-term contracts will maintain their market share. Cement industry forecasts envisage a 2 percent real growth in output per year thereafter, which may be too optimistic.

It appears that British Columbia will only supply 200 000 tonnes of thermal coal annually between 1982 and 1985 to the Japanese cement producers, with potential additional contracts totalling about 400 000 tonnes by 1990.

Total contracted Southeastern British Columbia thermal coal for export to Japan in 1985 is about 300 000 tonnes. An additional 450 000 tonnes will be shipped from the Quintette and Bullmoose mines in Northeastern British Columbia.[12] At least one additional supplier, McIntyre Mines, is under contract to ship 400 000 tonnes from Alberta. It is expected that the British Columbia producers will supply about 1.5 million tonnes of the total Canadian thermal coal to be supplied to Japan in 1985 and 2.5 million tonnes in 1990.

Japanese domestic coal mines have been major suppliers of soft coking coal (coal with higher volatile matter) to Japanese steelmakers, averaging about 6.5 million tonnes per annum. Here again, production levels are becoming more difficult to sustain due to technical factors. Anticipated contribution of indigenous coking coal to the domestic steel industry in 1985 is estimated to be much less, between 3.0 to 5.0 MMt. Table 2.3 shows metallurgical coal imports to Japan in 1981. Canadian supply represented approximately 14.0 percent of the total, with over three-quarters shipped from British Columbia.

The Ministry of Industry and Technology in Japan estimates imported coking coal requirements will be 65 to 67 million tonnes in 1990, a figure not appreciably greater than actual 1981 imports.[13] Nippon Kokan (NKK), a major Japanese Steel producer, has released a much higher import demand forecast. NKK estimated imported coking coal requirements at 70 million tonnes in 1985 and 79 million tonnes in 1990.[14] All in all, there is much confusion regarding long range requirements. Commitments with British Columbia producers in 1985 include contracts with B.C. Coal Ltd. totalling 4.7 MMt and with Denison Mines and Teck Corporation for 6.7 MMt.

Allegations have been raised that the Japanese have encouraged the development of major coal projects--such as the Northeast Coal Project in British Columbia--in order to flood the coal market in hopes that prices would become depressed. It appears that there may be some credibility to these allegations, as Japan has cut metallurgical coal demand by up to 35 percent of all import contracts in late 1982. In addition, Japanese government forecasts show a lower demand

for energy and for coal than projected earlier, leading to the belief that contracted amounts will not be required for some time. Japanese officials are quick to point out that part of the problem is the consistency of recent Australian coal shipments. Contracts were signed with other exporters on the premise that Australian supply would be as unreliable as during the prior year when labour and transportation problems caused major disruptions. British Columbia coal producers do have a major advantage over many other exporters in that the steel industry in Japan has a vested interest in a number of Canadian coal companies and projects. Among these are B.C. Coal Ltd., a company which is 33 percent Japanese owned, and Quintette Coal Ltd., which has a 42 percent Japanese project ownership. In many cases the Japanese steel industry will continue across-the-board reductions in contracted supplies, but where some measure of flexibility regarding cuts can be implemented, it will be advantageous to have Japanese equity.

The Japan Iron and Steel Federation (JSI) estimates contractual commitments with Canada will total 19.35 MMt by 1985 and 20.85 MMt by 1990.[15] Actual commitments are already 22.5 MMt for 1985. Under conditions of surplus supply, there is no room for further penetration of the market until after 1990. Cutbacks on existing contracts by approximately 25 percent per year to 1985 may be required and by 20 percent thereafter to 1990. British Columbia metallurgical coal exports to Japan in 1985 are forecast to be approximately 12.6 million tonnes and 13.5 million tonnes in 1990. This represents an increase over the historical contribution of British Columbia producers to the Japanese market, to over 20 percent.

Table 2.6 shows an estimate of British Columbia thermal coal to be exported during this decade, while Table 2.7 depicts estimates of metallurgical coal exports. Coal demand forecasts are under constant revision; currently downward. Tables 2.6 and 2.7 incorporate some optimistic assumptions regarding demand in the developing countries of Latin America and Asia, which may mean demand requirements will be at the lower end of the range.

TABLE 2.6

ESTIMATED THERMAL COAL EXPORTS
FROM BRITISH COLUMBIA[16]

Destination	1982 000's tonnes (actual)	1985 000's tonnes	1990 000's tonnes
Hong Kong	177	600 - 700	1 200 - 1 800
Japan	200	1 400 - 1 600	1 600 - 4 000
Korea	500	1 700 - 2 400	2 300 - 3 000
Taiwan	-	800 - 1 000	1 200 - 2 000
Other	-	100 - 200	200 - 400
Total Asia	877	4 600 - 5 900	6 500 - 11 200
European Economic Community	330	1 500 - 2 500	2 500 - 4 500
Total	1 207	6 100 - 8 400	9 000 - 15 700

SOURCE: For 1982 figures is Statistics Canada Catalogue 45-002, Coal and Coke Statistics, December 1982.

TABLE 2.7

ESTIMATED METALLURGICAL COAL EXPORTS
FROM BRITISH COLUMBIA[16]

Destination	1982 000's tonnes	1985 000's tonnes	1990 000's tonnes
Japan	6 420	12 000 - 14 000	13 000 - 14 000
Korea	1 500	1 900 - 2 100	3 200 - 3 600
Taiwan	520	1 000 - 1 500	1 500 - 2 000
Other	147	200 - 300	200 - 500
Total Asia	8 587	15 100 - 17 900	17 900 - 20 100
Brazil	-	1 300 - 1 500	2 000 - 2 300
Chile	51	400	600
Mexico	33	100	100
Total Latin America	84	1 800 - 2 000	2 700 - 3 000
Total	8 671	16 900 - 19 990	20 600 - 23 100

SOURCE: For 1982 figures is Statistics Canada Catalogue 45-002, Coal and Coke Statistics, December 1982.

Returns to producers are significantly lower than last year, when supply from Australia and Poland was uncertain (as were supplies from the U.S. due to a coal miners' strike). Table 2.8 shows average coking coal prices to Japan.

Thermal coal prices have undergone radical fluctuations. In 1981 alone, spot prices in Europe topped $80 per tonne (U.S.) as shortages were anticipated to arise from supply disruptions in Australia, the United States and Poland. By late 1981, prices had dropped down to $48 per tonne (U.S.) FOB and $63 per tonne (U.S.) in Europe.[17] Alternative suppliers had simply performed well, and importers benefitted from an oversupply. The situation in 1982 developed such that the coal spot market become virtually non-existent due to a low world oil price and reduced demand. Even at bargain prices of $40 to $45 per tonne (U.S.) CIF Europe via South Africa, exporters could not move coal. Importers in Europe and elsewhere had such extensive stockpiles they could make no further additions.[18]

Predictions for 1983 prices are bleak indeed. Thermal coal under long-term contracts to be signed in 1983 is projected to sell at $35 to $40 per tonne (U.S.) FOB pier out of Richards Bay, South Africa, and $41 to $49 per tonne (U.S.) FOB Australia.[19] This forecast is already becoming reality with a contract renewal signed between Japan's Electric Power Development Corp. and a South African producer for thermal coal at $39.50 (U.S.) per tonne FOB Richards Bay.[20] The coking coal market is also soft, and a new benchmark price has been negotiated for metallurgical coal, this time to Western European steel mills via Poland. The Polish producer has contracted for 6.5 million tonnes to be shipped in 1983 at $55.00 (U.S.) per tonne FOB terminal.[21] This price is down significantly from 1982 prices, and from the previous going rate in 1983 of $61.00 (U.S.). Table 2.9 shows average contracted thermal coal prices between Japanese importers and their primary sources of supply. Figures for 1983 are still relatively uncertain.

TABLE 2.8

AVERAGE IMPORT PRICES OF JAPANESE CONTRACTED COKING COAL
(FOB pier, Cdn$ per tonne)

	Canada	Australia	U.S. East	U.S. West	South Africa	U.S.S.R.	Poland
1980[a]	63.90	60.26	68.00[b] 80.75[c]	58.48	48.78	64.21	70.00
1981	69.01	64.43	73.15[b] 85.13[c,d]	64.33	64.91	U/A	N/A
1982	81.20	75.87	85.12	71.12	70.46	80.28	-[e]
1983[f]	87.50	66.13	70.83	58.71	54.39	U/A	-

SOURCE: C. Itoh and Company Ltd.

NOTE: U/A = unavailable, N/A = not applicable.

[a]In 1980, $1 Cdn. = $.855 U.S; in 1981, $1 Cdn. = $.834 U.S; in 1982, $1 Cdn. = $.809.

[b]This is high to medium-volatile bituminous coal.

[c]This is low-volatile bituminous coal.

[d]This price has an increment for rail changes.

[e]Coal contracts with Poland were discontinued in 1981, and will not be resumed.

[f]The 1982 exchange rate was utilized for conversions in this year.

TABLE 2.9

AVERAGE IMPORT PRICES OF JAPANESE
CONTRACTED THERMAL COAL
(FOB pier, Cdn$/tonne)

	Canada	Australia	U.S. East	U.S. West	South Africa	China
1981	56.95	57.53	62.69	-	51.56	50.25
1982	59.95	61.01	52.53[b]	65.87	59.43	68.53
1983	N/A[a]	N/A[a]	- [b]	- [c]	37.00[d]	43-50

SOURCE: C. Itoh and Company Ltd.

[a]The Japanese importers are waiting for coking coal contracts to be settled first.

[b]This is spot market only.

[c]This coal is no longer competitive.

[d]Prices will actually be lower over the year.

Footnotes

[1]Official Journal of the European Communities, C105, Volume 25, April 26, 1982, p. 9.

[2]Ibid., p. 22.

[3]Ibid., p. 2.

[4]Government of Canada, Ministry of Industry, Trade and Commerce statistics.

[5]Wilson Branco, "Coal in Brazil: Past Trends and Outlook," presented to the 34th Annual Canadian Conference on Coal in Toronto, September 19-21, 1982.

[6]Young-Soo Han, "Increasing Role of Canadian Coal," presented to the 34th Annual Canadian Conference on Coal in Toronto, September 19-21, 1982.

[7]Ibid.

[8]C. Itoh and Co. Ltd., "Market Report on Coking Coal and Steaming Coal" (Tokyo: C. Itoh and Co. Ltd., January 1982), p. 1. Economically recoverable reserves are estimated at 1 billion tonnes. See also, International Energy Agency, World Energy Outlook (Paris: OECD, 1982), p. 312.

[9]Ibid., p. 9.

[10]Yoshinori Satoh, "Views on Thermal Coal Imports by the Japanese Electric Power Industry - With Reference to Canadian Coal," presented to the 34th Annual Canadian Conference on Coal in Toronto, September 19-21, 1982.

[11]The Chase Manhattan Bank, N.A., World Coal Outlook The Year 2000: Opportunities and Uncertainties (New York: The Chase Manhattan Bank, N.A., October 1981), p. 13.

[12]Kai Consulting Inc., An Industrial Survey and Review of Western Canada's Export Potential, 1985 and 1990, 1982, Appendix Table 1.

[13]"Energy Market Reports: Coal," Financial Times: Energy Economist, June 1982.

[14]Financial Post, August 28, 1982.

[15]The Iron and Steel, "Canadian Coal - Current Status and Future Prospects," April 1982.

[16]The information contained in this Table has not been obtained specifically from any one source; many inputs were utilized to derive the forecast. These sources include the Official Journal of the European Communities, C105, Vol. 25, 1982; International Energy Agency coal publications; Coal Manual 1982 (Tokyo: TEX Report Ltd., 1981); C. Itoh and Co. Ltd., "Market Report on Coking and Steaming Coal," January 1982; numerous volumes of The Coal Miner 1980-1982; Kai Consulting Inc., Coal: An Industry Survey and Review of Western Canada's Export Potential 1985 and 1990 (Ottawa: Kai Consulting Inc., 1982); The Chase Manhattan Bank, N.A., World Coal Outlook The Year 2000: Opportunities and Uncertainties (New York: The Chase Manhattan Bank, N.A., October 1981); industry and government officials from Europe, Brazil, Korea, Japan and Canada.

[17]Energy Market Reports: Coal," Financial Times: Energy Economist, July 1982.

[18]Energy Market Reports: Coal," Financial Times: Energy Economist, Issue 12, October 1982.

[19]The large price range for the Australian coal is a reflection of quality differentials.

[20]Energy Market Reports: Coal," Financial Times: Energy Economist, Issue 16, February 1983.

[21]"International News," The Coal Association of Canada: Coal Focus, Issue No. 59, January/February 1983.

Chapter 3

TRANSPORT OF BRITISH COLUMBIA COAL

The development of British Columbia coal for export entails a three step transport system--from mine-mouth to a coastal port, maritime shipment to importing country and receiving and distribution at destination. Trans-shipment from one transport mode to another occurs at each of these stages with significant associated costs.

The distance from both the Northeastern and Southeastern coal deposits to tidewater is approximately 1100 kilometres. To accommodate regular shipments of large quantities of coal over such long distances, bulk hauling is required. Three transport options emerge with the potential of being economically viable: rail, slurry pipeline and truck. Only the first is examined in detail. The advantages of trucking--speed, convenience, lower terminal and overhead costs, and maneuverability--are outweighed by the extreme costs associated with the movement of large quantities by relatively small units of transport. Trucking comes into play for short hauls to the railhead when spurlines do not reach the mine mouth. These branch rail lines may not be built if tonnages to be transported are neither sufficiently great nor regular to overcome the additional rates charged as a result of the exceptional capital and operating costs required to build the line. In fact, in the United States 75 percent of all coal leaving the mine is transported by truck during some portion of the trip to the consumer.[1] Slurry pipeline transport is under consideration for the shipment of Alberta and British Columbia coal to tidewater for export, although actual projects are much further advanced in the United States. There, construction is imminent should legislative barriers be overcome. In Canada, the plans are still less certain and hence discussion in this paper will be limited to existing Canadian coal transport modes.

3.1 Railway Transport

There are two main rail routes for coal export which must be considered in the British Columbia context; the first from the Crowsnest area in the southeast, the other partially under construction from the Peace River area in the northeast. The ultimate Canadian destinations differ for both routes as do their particular problems and circumstances, hence they will be discussed separately. Figure 3.1 which follows shows both in closer detail.

3.1.1 Southeast Route

The single most controversial and immediate issue concerning rail transport in Canada involves grain freight rates. The Crowsnest Pass Agreement was drawn up in 1897. Although the initial intent was political, its ramifications in the 1980s are primarily economic. Canadian Pacific Railways (CPR) agreed to complete a rail line from Lethbridge, Alberta to Nelson, British Columbia and run it in perpetuity. In return, the federal government subsidized the line by $11,000 per mile and granted 50,000 acres of coal property to the CPR. The main thrust of the government's dealing was to limit American influence in mineral-rich southern British Columbia by offering a rail line which linked the area with the Prairies. The component of the agreement which is of current consequence resulted from pressure exerted by prairie farmers who felt that the Canadian railroads were charging unjustly high freight rates for grain shipments. It was agreed that the CPR was to transport grain and flour (and later rapeseed) at 0.05 cents per tonne mile to the Lakehead (at Thunder Bay). Later revisions required that all grain transported on the railway system was to be eligible for this rate. This 1897 rate is now fixed under the National Transportation Act, a parliamentary response to CPR and Canadian National Railways (CNR) instigated court battles intending to raise the rates.

Early in the next session of Parliament, the Federal government will seek approval of a new freight rate structure designed to replace the existing Crowsnest Pass system. Under the new regime, prairie farmers will be paying twice as much to ship their grain by 1985 and perhaps five times the

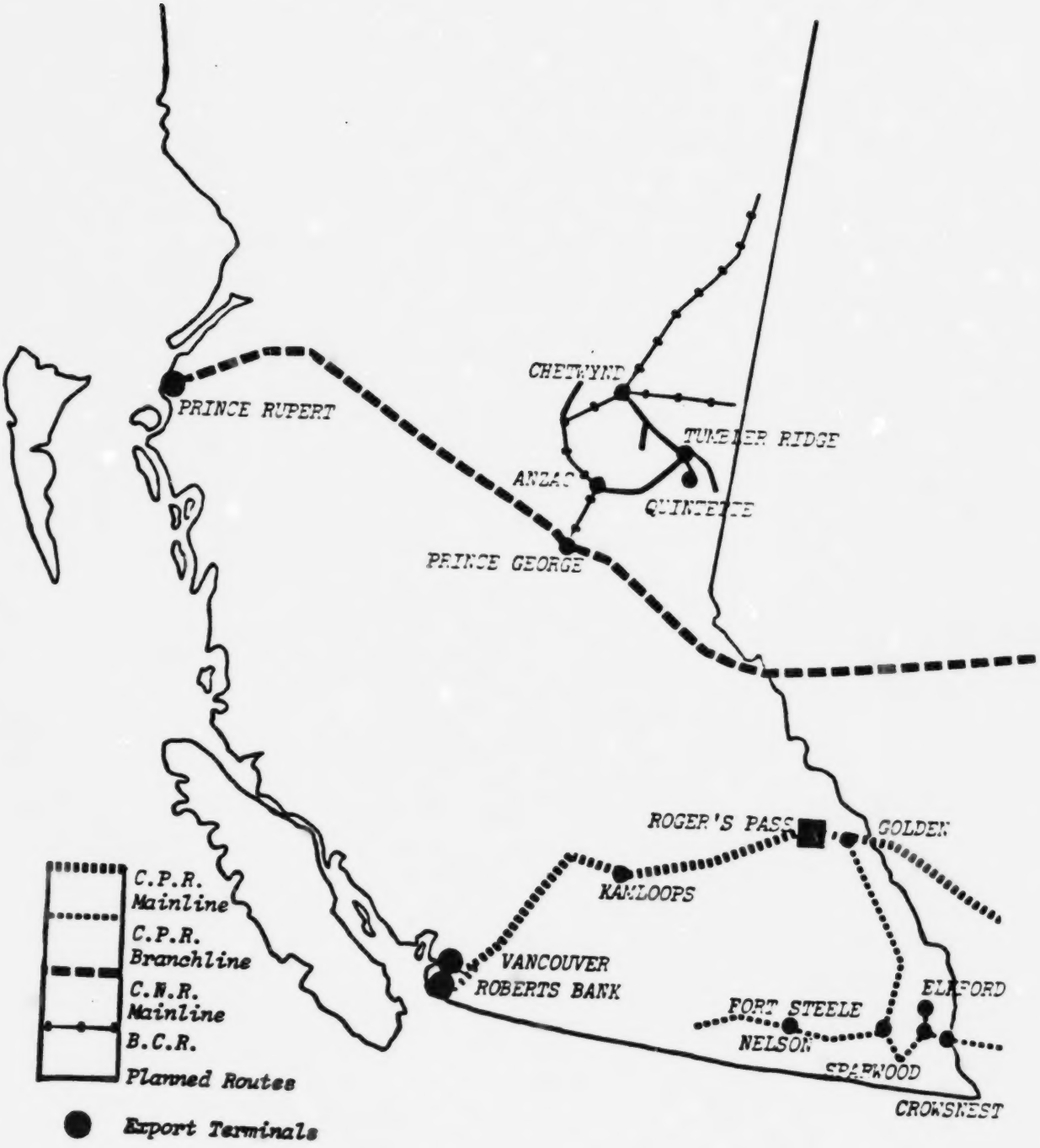

FIGURE 3.1: Rail Export Routes

old rates by 1990. To ease the transition from the Crow Rate to the new scheme, the Federal government will spend $3.5 billion over four years to subsidize farmers' transportation costs and stimulate railway upgrading.[2] By 1990, an additional 8 MMt of grain would be transported by an upgraded system each year. Because of the increased costs to farmers, the new scheme is opposed by the three largest western grain cooperatives: Saskatchewan Wheat Pool, Manitoba Pool Elevators and Alberta Wheat Pool.

The major current problem is that many commodities compete for a rail line with limited capacity. In addition to grain, coal, sulphur, potash and petrochemicals are commodities for which significant growth in worldwide demand is projected thereby increasingly taxing existing transport facilities. There is one section of the westward route which presents a severe bottleneck--the Rogers Pass in the Selkirk Mountains. The grade is currently 2.6 percent requiring 12 engines to haul 100-car (average) unit trains.[3] Capacity limits could be reached during the next two or three years, as only 15 westbound trains per day can pass through the area. On average, 3.3 of these trains haul coal. CP Rail has a grade improvement project planned which involves building two new tunnels--the 14.5-kilometre Beaver Tunnel, plus a 1.6-kilometre tunnel--and 33.8 kilometres of double tracking. The grade would then be reduced to meet the one percent maximum of the other sections of the line, therby raising operational capacity to 19 westbound trains per day. CP officials estimate the cost of this construction to be in excess of $500 million current Canadian dollars.[4] Although this represents only a fraction of total $7.7 billion projected by CPR for capital expenditures to 1990, without this single program to alleviate congestion other proposed expansions of the CPR network in western Canada would be rendered relatively useless. The dilemma facing Canadian Pacific Railways is that a capital shortfall for proposed expansions to 1985 would be about $1.5 billion in current Canadian dollars. The significance of the Crowsnest Pass Agreement becomes apparent. Although the encouragement of grain production and export has enabled Canada to become a major international supplier, CPR estimates a loss attributable to grain shipment in 1981 at about $200 million[5]. This figure would rise with inflation and increasing quantity shipped.

Under a new government package, railway subsidies of $315 million will enable the CPR to commence improvements this year.

3.1.2 Northeast Route

Coal from the Peace River area must travel via the British Columbia Railways (BCR) to Prince George and then along the Canadian National Railways to Prince Rupert. Although other commodities are currently tranferred along this main rail route from Edmonton, it will be the influx of coal from the mines in the north of British Columbia which will put pressure on current operational capacity. The first mines of northeastern British Columbia are forecast to come on stream in early 1984. CNR anticipates the need for heavier tracking, a centralized train control system and longer sidings on this 744-kilometre section at a total cost of $350 million current Canadian dollars.[6] As with CPR, this amount represents only a small portion of the total planned capital investment to 1985, estimated at $2.6 billion.[7] Although the company had formerly anticipated a shortfall of expenditures and revenues of well over a billion dollars, the proposed Crow Rate revisions will most likely eliminate the deficit.

British Columbia Railways, a provincial Crown corporation, is to build a 129-kilometre branch rail line from the town of Anzac on its existing line to the new townsite of Tumbler Ridge and to the Quintette property. This line will carry coal from area mines including those at Quintette and Bullmoose along the BCR to Prince George. From this point the coal will move via the CNR mainline to Prince Rupert. An interesting feature of the new branchline is that it is to be the second North American 50-kilovolt electric railway. There are both favourable and negative elements to such a decision.

A major cost component of the new branchline is the blasting of two tunnels, the 9.1-kilometre Table Tunnel and the 6-kilometre Wolverine Tunnel. Extra ventilation in the tunnels, at an estimated cost of $15 million in 'as-spent' Canadian dollars, can be eliminated with electrification.[8] Diesel locomotives tend to stall in high temperatures which

would occur in unventilated tunnels. Electric locomotives get better traction (an important feature for a heavy snowfall district) which means that fewer engines are required, they have double the economic 'life' of the diesel engines, and cost about one-third as much as diesel to maintain. Electric locomotives also use an abundant easily accessible renewable energy source. There is a 230-kilovolt transmission line approximately 2 kilometres away from the substation to be built along the rail route. The single largest disadvantage is that the initial capital cost associated with installment of overhead electric wires is very high, requiring a large traffic throughput in order to realize the aforementioned cost advantages. In this respect, it is unfortunate that the initial construction on many of the planned mines in the area has been postponed indefinitely and the sluggish world market for metallurgical coal may lead to further reductions in anticipated traffic levels.

Other components of the new line include eleven bridges, and two smaller tunnels. The maximum grade for the loaded trains will be 1.2 percent. In addition to the new line, BCR is to upgrade its existing 124-kilometre line to Prince George to accommodate a heavier traffic flow. Total capital cost is anticipated to be $467 million current dollars.[9] Originally, the province was to pay for the new line through operating revenues, but inflated costs have required the borrowing of funds. Interest changes alone are anticipated to add $80 to $100 million to the cost of the line. The unit trains used on the northeast route will initially be purchased by CNR. The coal companies will share some of the cost in proportion to usage. At least nine unit train sets consisting of 98 cars, a caboose and locomotives, will be required when the two mines are operating at full capacity.

3.1.3 Freight Costs

There are three cost components directly associated with the rail transport of coal: loading of unit trains, rail transit, and unloading at the terminal. There are also costs attributed to the movement of coal to the railhead. Two forms of transfer are most commonly used; conveyor belts and trucks.

Conveyor costs are highly dependent upon the capacity of the system. The Cable Belt system, which is capable of handling volumes to nearly 40 million tonnes per year and can transport over significant (greater than 10 kilometres) distances, requires a minimum capacity of about 300 tonnes per hour or 2.2 million tonnes per year. Although the ultimate throughput of 2.3 million tonnes per annum at the Teck Corporation's Bullmoose Mine will surpass the minimum required, it does so by a very small amount. The coal from Bullmoose is to be trucked 35 kilometres to Tumbler Ridge. On the other hand, throughput at the Quintette mine of greater than 1800 tonnes per hour, is more than sufficient to make the use of conveyors practical. The 13-kilometre conveyor system to be in place at the Quintette mine is exceptional in that the belt runs downhill to the railhead. Energy is actually generated, not consumed. Site buildings and facilities will utilize this energy, reducing operating costs.

The calculation of the costs associated with coal transport via conveyors and trucks is beyond the scope of this paper, but a range of conservative estimates can be obtained. The cost of conveyor transport may vary from between $0.03 to $0.10 per tonne-kilometre for a conveyor of 13 kilometres, whereas the costs associated with truck haulage can be much higher with the $0.10 per tonne-kilometre as a minimum. All figures are given in 1982 Canadian dollars.

An in-depth analysis of coal freight rates can be found in a working paper published by the Canadian Energy Research Institute entitled "Potential Markets for Thermal Coal in Canada, 1978-2000."[10] More recent figures suggest that, given a distance of approximately 1200 kilometres from the southeastern producing region to tidewater, the average charge for rail transport was $16.25 per tonne or $0.015 per tonne-kilometre in 1981.[11]

Freight rates to be charged to the Denison and Teck projects are based upon mid-1980 rates of $15.86 and $15.76 per tonne, respectively, although a development concession of $2.00 per tonne (non-escalating) will reduce the rates for the first five years of utilization. The base rates will escalate at 12 percent per year on 80 percent of the 1980 charges. In other words, the rate in 1984, when coal

shipments are to begin, would be about $22.85 per tonne to Denison and $22.71 per tonne to Teck Corporation. There will be an additional premium to be paid by the users of the new BCR Anzac spurline. The surcharge will be $3.00 per tonne to Denison and $2.50 per tonne to Teck, non-escalating to 1989. The rate of escalation from 1989 onwards will follow increases in coal prices.

The port dues encompassed under the maritime transport costs discussed in a later section account for costs attributed to transshipment from unit trains to ships. These estimated costs are shown in Table 3.1.

3.2 Maritime Transportation of Coal

Ocean shipping of coal is accomplished primarily through the use of bulk carriers with conventional dry cargo vessels and combination ore-bulk-oil carriers (OBO's)[12] accounting for the remainder. In recent years the average size of these ships has been increasing due to economies of scale and hence lower unit operating costs associated with increased size and longer distances travelled. Especially significant has been the emergence of the Japanese coal import market which utilizes many of the new 'Supercolliers'--ships of about 300 metres in length and capacities of 100 000 dead weight tonnes (dwt) or greater.[13] These new coal transport vessels parallel very closely the development of the 'supertankers' used in oil transport. The average international coal cargo was 60 000 tonnes in 1979, more than double the mean of 1969.[14] The rate of utilization of the larger vessels, 65 000 dwt or greater, has been limited by three major factors--shiphandling facilities at ports, dimensions of canals and the average eighteen-year lifespan of smaller vessels in current use which are not yet fully depreciated. The average size of the vessels will become larger as these conditions change with increasing coal demand on the world markets, although some maximum may be reached, predictably about 250 000 dwt. This will be the maximum capability of any port projected to be built in this century. Beyond this level, the necessary capital requirements for loading, unloading and dredging would outweigh the advantages of scale economies. A limit to the mid-size vessel would be 150 000 dwt as this adheres to maximum Suez Canal dimension

TABLE 3.1

ESTIMATES OF TRANSSHIPMENT COSTS
AT TYPICAL EXPORT TERMINALS
(1982 $Cdn.)

	Annual Capacity (MMt/yr)	Capital Cost (10^6 $)	Operating Cost (10^6 $/yr)	Total Costs at Full Utilization ($/t)
Unit Train, rotary unloading:	10	13	3.1	0.44
Ship, loading from stacker reclaimer:				
- Roberts Bank Type	10	63	3.1	1.06
- Ridley Island Type	10	138	8.1	2.44
Total transshipment costs:				
- Roberts Bank Type	10	76	6.2	1.50
- Ridley Island Type	10	151	11.2	2.88

SOURCES: International Energy Agency, Canadian Energy Research Institute.

NOTE: Figures may not exactly correspond to numbers used to describe the two export terminals as cited later in this paper. Estimates are for any ports which are of a comparable nature to the Canadian facilities. For example, these figures reflect costs of offshore loading dock facilities similar to those planned for Ridley Island.

restrictions. Passage through the Panama Canal is limited to fully loaded ships of 65 000 dwt or ballast ships of 80 000 dwt, so this size of ship will still be widely utilized.[15]

At the present time Canada does not have its own deep-sea merchant marine but many Canadian companies own ships that are registered through other countries.[16] Proponents of Canadian flag-ships cite the domestic employment opportunities and the balance-of-payment advantages (Canadian deep-sea trading transportation costs are annually about $4 billion Canadian).[17] Opponents argue that higher freight charges would result due to probable government intervention and relatively higher Canadian wage rates.[18] As the federal government has not offered the financial incentives needed to establish a competitive fleet, reliance upon foreign ships will continue for the foreseeable future.

3.2.1 Port Facilities

There are three existing British Columbia port facilities which handle coal exports: Roberts Bank, Vancouver and Port Moody. A fourth port at Prince Rupert on Ridley Island is forecast to begin coal handling early in 1984. The relative importance of these ports in the long-term export of coal will, to some degree, be limited by physical expansion constraints. In order that a port be capable of receiving vessels of 100 000 dwt or greater, minimum channel depth of about 15 metres is required. In the past, train cars carrying coal waited inland and were brought to the terminal site solely for direct loading onto ships. The unit train concept of present day necessitates fast throughput in order to gain cost advantages. Consequently, modern coal handling terminals must have substantial stockpiling capacity. A minimum requirement is about 10 percent of maximum annual throughput, and the two Vancouver terminals do not meet this standard for coal handling. Table 3.2 shows both existing terminals and those currently under construction as well as the characteristics which will limit operational capacity.

TABLE 3.2

COAL EXPORT TERMINALS - BRITISH COLUMBIA

Statistics	Roberts Bank Westshore Terminals		Vancouver Neptune Bulk Terminals 1982	Port Moody Pacific Coast Terminals 1982	Prince Rupert Ridley Island Terminal Phase II 1983	Total 1983	Possible Expansions to 2000	
	Phase I 1982	Phase II 1983					Roberts Bank	Ridley Island
Maximum annual coal capacity (MMt/yr)	20+[a]	30	5.5	2	12	49.5	20	12
Maximum vessel size (dwt)	170 000	250 000	90 000	65 000	50 000	-		
Total area (ha)	22	40	30	40	25	135	40	25
Stockpiling capacity (Mt)	950-1400	2000-2200	400	110	1200	2610-2810		
Maximum draft (metres)	18	21	15	13	20[b]	-		
Cost (millions current Cdn.$)	13	130	N/A	N/A	290	373		
Rail Connections	CPR, CNR, Burlington	Northern	CNR, BC Rail	CPR	CNR			

SOURCES: Canada West Foundation and conversations with port officials.

[a]Although the rated throughout capacity of the Roberts Bank Coal Terminal was rated only 10 MMt per year, 1980 saw a throughput of almost 11.5 MMt.

[b]The 20-metre draft is actually the minimum which will be encountered by ships passing through the Ridley Island facility.

Port charges at existing facilities vary from customer to customer depending upon quantities shipped and length of contract with the port. It is difficult to ascertain an average charge per tonne, although the figures shown in Table 3.1 give an idea of minimum charges required to cover costs. As the coal terminal at Prince Rupert is a portion of the larger project of Northeast Coal development, its port charges are more clearly depicted. The base charge is set at $3.00 per tonne, in 1980 Canadian dollars. Escalation will occur at 9.6 percent per year. This will mean a charge of $4.33 per tonne for the first shipments in 1984. These rates can be renegotiated in 1989, to a maximum increase of about 20 percent of the 1989 charge.[20]

3.2.2 Shipping Costs

Maritime coal transport is generally conducted under long-term, time-chartering contracts on a FOB (Free On Board) or FAS (Free Alongside Ship) basis. Freight charges are the responsibility of the buyer and shipping contracts stipulate a return on capital to the owner as well as some escalating operating cost recovery. Time spot charters or so-called voyage chartering will occasionally be utilized for a specific shipment. The freight rates under these short-term contracts vary radically with respect to demand at the moment of charter, whereas the long-term rates are moderated from the extreme spot quotes at the moment of contract approval.

As ocean transportation costs can represent up to 30 percent of the CIF (carriage, insurance, freight) price of coal, any savings which can be attained in this area are of considerable importance. Although most Canadian coal is sold on a FOB port basis, the significance of ocean freight charges cannot be denied. These charges must still be incurred and add to the ultimate cost of the coal to importers. As British Columbia coal must often travel extensive distances to consuming nations, the cost of maritime transport will influence negotiations with B.C. producers. As mentioned earlier, economies of scale comprise one saving. Estimated freight rates between Vancouver and Japan as of March 1979 were $16.30 (U.S.) per tonne for a vessel of 20 000 dwt as opposed to a $9.00 (U.S.) per tonne for a 60 000 dwt ship.[21]

While freight rates are determined on the market and countries must bid to contract ships from this same market, shipping distance becomes a major determinant of total freight costs. This of course assumes that bidders ultimately attain similar freight rates. West coast Canadian shippers have a cost advantage over the east coast United States shippers when trading with the Pacific Rim countries. This is intuitively apparent and it can be seen from the distances between ports as shown in Table 3.3. In fact, during the month of December 1981, the single trip ocean rate per long ton from the Port of Vancouver to Japan averaged $7.00-$10.00 (U.S.) for a ship of 60 000 dwt. A similar rate out of Hampton Roads, Virginia late in 1981 ranged between $18.50-$19.10 (U.S.) a long ton.[22] Distance also dictates an eastern U.S. advantage for western European markets; the rates to this destination were considerably lower at $7.00-$7.75 (U.S.) in September of 1981.

Fuel costs are one major determinant of freight rates. With the escalating costs of bunker fuel oil, feasibility studies and pilot projects have examined the viability of coal as a bunker fuel. Initial capital costs are greater for this type of ship and storage is more difficult owing to the bulkiness of the fuel. The long-run operating costs associated with fuel cost savings makes this an economical alternative, especially in the case of coal-carriers which would have an internal fuel supply source.

The prices quoted above are for spot-charters and as such are the only readily available figures as prices under long-term contract are negotiated privately and are rarely available to the public. There is, however, one consolation. Unlike the unpredictable nature of spot prices, long-term freight rates closely follow actual costs associated with the vessels. The cost derivation will be a measure of long-run economic cost which includes long-run capital charges required to replace the ship at the end of its life with a similar ship at current prices. This is not an accounting or historic cost. Prices will run close to this derived cost over the long-term, although deviations for short-term contracts may occur due to immediate market fluctuations.

TABLE 3.3

MARITIME TRADE

Exporting Country		West Germany		Japan (average)	
		Days (steaming at 13-14 knots)	Distance (nautical miles)	Days (steaming at 13-14 knots)	Distance (nautical miles)
Canada-Vancouver	Canal Route	28-30	9,200		
	Cape Route	44-47	14,800	14-15	4,400
United States-Portland	Canal Route	28-30	9,000		
	Cape Route	44-47	14,700	14-15	4,300
United States-Hampton Roads	Canal Route	12-13	3,700	30-32	9,800
	Cape Route			45-49	15,200
Australia-Hay Point	Canal Route	36-39	11,800	13-14	4,200
	Cape Route	42-45	14,000		
South Africa-Richards Bay	Canal Route				
	Cape Route	22-24	7,400	21-23	7,200

SOURCES: International Energy Agency and The Coal Miner, Sept. 1980, p. 14.

NOTE: These numbers are approximations and consequently any variations in results may be attributed to rounding, time spent in canal passage, and other route deviations.

Estimated costs between Canada and Japan are derived for three existing ship sizes: 60 000 dwt or 'Panamax' size, the maximum size of fully loaded vessel that can pass through the Panama Canal; 100 000 dwt vessel, the average large-size ship; and 150 000 dwt, the current maximum size vessel in use for coal transport.[23] Future costs include 200 000 dwt vessels as these will be in use in this century, especially with increasing thermal coal trade. The ships are of the dry bulk type as this will continue to be the most common transport vessel in the period. The one major modification for future costs will be the introduction of coal-fired carriers. Table 3.4 and Table 3.5 show the results for transport from the Vancouver area and from the new Ridley Island Terminal which is closer to the Japanese market.

3.3 Receiving Facilities

The capabilities of the Canadian coal export transportation network are of little significance unless the purchasers of our coal have the facilities to receive and distribute it. A case in point is the Japanese transshipment facilities.

At the present time there are three existing types of trans-shipment ports for coal in Japan: public, private and those owned by steel companies.

The public ports are limited in storage area, throughput and maximum vessel size capabilities. Two of the seven existing ports are too far from coal consumers to be of any considerable assistance. Two ports are relatively new and operating close to capacity levels, while three others are already over-extended. As the maximum size of ship that can be received at any of these ports is 50 000 dwt, it appears that unless new terminals are built (none are anticipated), it is not through the public system that expanded coal imports will be handled.

There are currently three privately owned mini-coal centres with capabilities much greater than the public ports. Two are presently undergoing expansion which will raise yearly throughput for all three facilities to between seven and twelve million tonnes by 1985. One port, Ube, will

TABLE 3.4

ESTIMATED SHIPPING COSTS - VANCOUVER TO JAPAN
(1982 $Cdn./tonne)

Vessel Size (dwt)		1982	1985	1990	1995	2000
60 000	OF	18.3	18.5	19.5	21.0	22.6
	CF	-	-	-	20.1	21.4
100 000	OF	14.3	14.5	15.5	16.8	17.9
	CF	-	-	-	15.9	17.0
150 000	OF	12.4	12.6	13.4	14.4	15.3
	CF	-	-	-	13.6	14.6
200 000	OF	11.8	12.0	12.8	13.8	14.6
	CF	-	-	-	12.9	13.9

TABLE 3.5

ESTIMATED SHIPPING COSTS - PRINCE RUPERT TO JAPAN
(1982 $Cdn./tonne)

Vessel Size (dwt)		1982	1985	1990	1995	2000
60 000	OF	16.6	16.9	17.9	19.1	20.6
	CF	-	-	-	18.1	19.3
100 000	OF	13.1	13.3	14.1	15.3	16.3
	CF	-	-	-	14.3	15.4
150 000	OF	11.4	11.7	12.3	13.3	14.2
	CF	-	-	-	12.5	13.3
200 000	OF	10.9	11.1	11.7	12.7	13.6
	CF	-	-	-	11.8	12.9

NOTE: OF designates oil-fired vessels
CF designates coal-fired vessels

initially be capable of handling ships of 100 000 dwt if problems of shallow draft at the port can be overcome.

Japanese imports of metallurgical coal are received directly through ports built especially by the steel companies. Given the extensive storage and handling facilities of these ports, there is the capacity for trans-shipment of coal to other users as well. A number of steel companies are considering such coal distribution but only one company--Nippon Kokan--has actually allowed this trans-shipment. Expansion of its NKK Coal Centre with a new port to handle 200 000 dwt supercolliers will increase total combined capacity to between three and five million tonnes per year. If no new steel plants are built on the new facility, then thermal coal could be shipped more extensively. Total port throughput is projected to be sufficient even under the fairly optimistic metallurgical coal throughput forecast to the year 2000 by the World Coal Study (WOCOL).[24] The major problem may be insufficient capacity for thermal coal imports.

As discussed earlier, there is little room for expanding the capacity of existing facilities. This problem has led to the formulation of the concept of major coal centres with substantial storage areas capable of handling large throughput volumes and vessels. Although no such centres are certain to be built yet, there are at least four projects under consideration, each capable of receiving 100 000 dwt vessels and one capable of handling 250 000 dwt vessels. All projects will be able to handle a minimum of four million tonnes per year. In fact, coal is not likely to be the only commodity to be handled. Trans-shipment of other commodities such as iron ore, liquefied petroleum gases (LPG) and industrial products is also under consideration. Two large electric companies are each backing one of the projects. Their support may give added impetus to these proposals. Power companies are eager to avoid the secondary transportation costs and complications associated with barge shipment of small quantities of coal. Hence, proximity of power generation facilities to the port centres is of utmost importance.

TABLE 3.4

ESTIMATED SHIPPING COSTS - VANCOUVER TO JAPAN
(1982 $Cdn./tonne)

Vessel Size (dwt)		1982	1985	1990	1995	2000
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100 000	OF	14.3	14.5	15.5	16.8	17.9
	CF	-	-	-	15.9	17.0
150 000	OF	12.4	12.6	13.4	14.4	15.3
	CF	-	-	-	13.6	14.6
200 000	OF	11.8	12.0	12.8	13.8	14.6
	CF	-	-	-	12.9	13.9

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	CF	-	-	-	14.3	15.4
150 000	OF	11.4	11.7	12.3	13.3	14.2
	CF	-	-	-	12.5	13.3
200 000	OF	10.9	11.1	11.7	12.7	13.6
	CF	-	-	-	11.8	12.9

NOTE: OF designates oil-fired vessels
CF designates coal-fired vessels

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Japanese sources also anticipate no domestic transportation infrastructure changes until the year 2000.[25] Some investment will, therefore, have to be made to increase the fleet of barges and coastal vessels required to transport coal from trans-shipment terminals inland or along the coast. This portion of the transportation network should pose no barriers to projected import requirements, given the relatively long-term planning horizon and minor revisions envisioned.

The bulk carriers that haul coal to Japan most often sail under the Japanese flag. Unless there is some radical deviation from this norm, and there does not appear to be, increased thermal coal imports will require closely matched additions to the Japanese fleet. Vessel size can be categorized under two capacity ranges--those over 100 000 dwt and those below 100 000 dwt. The average size ship in each category is about 111 000 dwt for the former and 65 000 dwt for the latter. In 1977, Japan required four ships of the first size category and five of the second to handle coal import requirements.[26] As coal demand figures are anticipated to be much greater by the year 2000, demand for vessels will also increase. This implied increase indicates one area where the Japanese system may fail to keep up with projected demand. It is also one segment of transport costs where substitution away from domestic toward international suppliers can occur.

It is difficult to estimate the constraints that future coal trade will place upon shipbuilding facilities, as this will be influenced by many factors including the demand for oil tankers, ship life and the increase in demand for other dry bulk commodities. The early 1980s have seen an oversupply of bulk carriers with shipyards working under capacity. Total seaborne trade peaked in 1979 and then decreased in both 1980 and 1981. This trend is forecast to continue into the mid-1980s. When demand increases, first existing ships, then underused shipyards will be placed into commission. Japanese shipyards in particular have seen orders fall 840 000 tonnes in the first quarter of 1982 and therefore are working greatly under capacity.[27] In 1979, seaborne movement of 160 million tonnes of coal was transported by only 26 million dwt of vessels.[28] The

Organization for Economic Co-operation and Development (OECD) estimates required bulk carrier tonnage for the year 2000 to be between 90 million to 150 million dwt, a gradual increase of only 6 million dwt per year from current levels.[29] The major portion of the increase will occur between 1990 and 2000 as demand is expected to be moderate until that time. If Japanese capacity is not sufficient, it appears that as long as coal buyers are willing to pay for the use of foreign carriers, there should not be any deficit capacity for coal shipments.

The other Pacific Rim countries present smaller markets for Canadian coal than Japan but their demand and ability to accomodate projected demand are of importance. Both Hong Kong and Korea are building new port and terminal facilities in conjuction with coal-fired generating plants. Utility and cement industry conversions with subsequent increased demand have led to current facility expansion and new port planning. It appears that receiving centres will not impede Asian importers.

Although the infrastructure of the European Community is well established, many countries, including Italy, Spain, Portugal, Greece and Sweden have limited capabilities for the handling of larger vessels. There is some recourse to other countries' port facilities when large vessels are used, but, the additional trans-shipment charges undermine the lower costs resulting from economies of scale in volume shipment. The B.C. producers need some advantage in the form of infrastructure improvement in order to compensate for large travel distances, otherwise they will lose out to other exporters trading with these countries.

Brazil has also undertaken to increase its port capabilities. Two new piers, one of which is capable of receiving vessels up to 180 000 dwt, are scheduled for startup in mid-1983.

Any modification or new construction which enables the larger coal vessels to dock in a larger number of countries will be advantageous to Canadian suppliers. Economies of scale associated with large volume handling represent considerable cost savings. This is particularly

important for British Columbia producers as the distances from production to market centres are always substantial.

Footnotes

[1]H. M. Lee, The Future Economics of Coal Transport, EAS Report No. D2/79 (London: International Energy Agency, 1980), p. 45.

[2]The Globe and Mail, February 2, 1983, p. B1.

[3]A figure of 2.6 percent means that the grade rises 2.6 feet for every 100 feet of distance.

[4]J. D. Bromley, presentation to the Coal Association of Canada meeting on "Canada's Crisis in Rail Transportation Capacity" in Vancouver, August 6, 1981, p. 122.

[5]Ibid., p. 127.

[6]Canadian National Railways, "A Synopsis of a Presentation on Traffic Growth Capacity Capital Requirements," presented to the Coal Association of Canada meeting on "Canada's Crisis in Rail Transportation Capacity" in Vancouver, August 6, 1981.

[7]The Globe and Mail, February 2, 1983, p. B1.

[8]The Globe and Mail, July 5, 1982, p. B7.

[9]The Globe and Mail, August 21, 1982, p. B1.

[10]Canadian Resourcecon Limited, "Potential Markets for Thermal Coal in Canada, 1978-2000," (Calgary: Canadian Energy Research Institute, June 1979), Working Paper No. 79-2.

[11]The Coal Association of Canada, Towards an Equitable Commodity Transport System (Calgary: The Coal Association of Canada, June 1981), Appendix.

[12]As the name suggests, these are bulk vessels which can carry oil in addition to a dry bulk cargo.

[13]The Coal Miner, September 1981, p. 12. Deadweight tons or tonnes measure the cargo capacity of the vessel with the deadweight being the loaded displacement minus the empty displacement. Tons in this case are synonymous with metric tonnes, the spelling used in this paper.

[14]F. Anton, The Canadian Coal Industry (Calgary: Detselig Enterprises Limited, 1981), p. 119.

[15]H. M. Lee, The Long Run Economics of the Ocean Transport of Coal, Report No. D1/78 (London: International Energy Agency, December 1978), p. 8.

[16]Canadian registered lakers predominate in Great Lakes-Seaway shipping and some newly available ocean-going lakers are on order.

[17]The Financial Post: Special Report, December 12, 1981, p. 17.

[18]The Financial Times: International Coal Report, September 25, 1981.

[19]The draft is the vertical distance between the bottom of the ship as it sits in the water, and the waterline.

[20]Price Waterhouse Associates Management Consultants, Quintette Coal Ltd., Teck Corp. The North-East Coal Project: An Assessment of Public Sector Investment and Job Creation Impacts (Vancouver: Price Waterhouse and Associates, April 1981), p. 20.

[21]F. Anton, op. cit., p. 19.

[22]The Financial Times: International Coal Report, September 25, 1981. The freight rate figures are given as a range of values simply because rates vary according to changing market conditions as well as for each chartering contract.

[23]See Appendix A.

[24]World Coal Study, Future Coal Prospects (Cambridge: Ballinger Publishing Company, 1980), p. 286. Any statistics quoted from this source will either show a range of forecasts or the low coal case.

[25]Ibid., p. 287.

[26]Ibid., p. 286.

[27]Petroleum Economist, March 1982, pp. 93-94.

[28]The Globe and Mail, August 23, 1982.

[29]Ibid.

Chapter 4

DOMESTIC DEVELOPMENT OPTIONS

The coal produced in British Columbia can be categorized as either metallurgical or thermal. This chapter will focus on four development options that utilize thermal coal. All options would entail coal consumption within British Columbia borders. The first option is to use the coal for electricity generation; the second would convert the coal to liquid form; the third, to increase utilization of coal by energy-intensive industries in the province; and the fourth is the conversion of coal to gas. Options for the development of metallurgical coal for use in British Columbia are limited, and are briefly summarized below.

Less than 50 000 tonnes of metallurgical coal were consumed in British Columbia in each of 1980 and 1981.[1] Unless a new steel industry is developed on the west coast--which is unlikely given the prevailing market conditions--metallurgical coal consumption will continue to be minimal. As for utilizing British Columbia coal in the industrial markets of eastern Canada, the cost advantage of the Northeastern U.S. coal will be sustained, at least over this decade. The Steel Company of Canada Limited (STELCO) is involved in a joint mining venture on the Elk River property in Southeastern British Columbia. The 25 percent STELCO interest led to a committment to receive 1.0 million tonnes per year of Elk River metallurgical coal at the company's Hamilton operation. Unfortunately, the total projected mine production of 4.0 million tonnes per year could not be fully contracted. Moreover, because the other buyers committed to the project did not require the coal as early as had previously been anticipated, the project has been delayed until at least the late 1980s. Infiltration of Canadian markets will thus remain small relative to the potential of export markets.

4.1 Thermal Generation

A promising area of expansion for British Columbia coal use may be electricity generation. A major coal-fired generation project was recently under consideration by the British Columbia Hydro and Power Authority, slated to be in service by 1992. In August 1982, this project in the Hat Creek area of British Columbia was 'indefinitely postponed'. The fact that projected construction costs increased over 100 percent from a 1980 estimate of $4 billion (in 'as spent' Canadian dollars) to $9 billion in 1982, was a major factor in the decision.[2] The amount of planning already undertaken by British Columbia Hydro, the magnitude of the project and the provincial government's desire to diversify generation modes, lead to the conclusion that the project may eventually proceed as electricity demand increases. The project is therefore, included in this examination of development projections for British Columbia coal.

Hat Creek has one of the thickest coal zones in the world and probably represents the largest resource in the smallest area--26 kilometres by 5 to 7 kilometres. Coal deposits have been estimated at 10 to 15 billion tonnes.

The potential for the offsite sale of Hat Creek coal is low due to high ash content (averaging 32.5 percent), and the availability of better quality thermal coal for domestic or export use. The high ash content and complete absence of coking properties render production of this coal for metallurgical purposes technically unfeasible. The enormous quantities of coal available through low cost surface mining and the increasing impetus to meet domestic energy demand with domestic supply had prompted B.C. Hydro to plan the development of the Hat Creek area for electricity generation. There would be three major components to the project: an open pit mine and power plant, both located in the northern end of the Hat Creek Valley, and offsite facilities including service roads and a water supply pipeline. The economic operating life of the project is assumed to be 35 years, with 336 million tonnes of coal to be extracted over the project life.[3] At full capacity, the generators would produce 2000 megawatts.

Even with capital cost estimates far below current assessments, there is still a very high generating cost associated with the Hat Creek venture. The estimated unit cost of electricity generation at the station, assuming capital costs of $4.5 billion dollars ($1981) for four 150-megawatt (MW) units, is shown in Table 4.1.

As mentioned above, the costs associated with electricity generation of Hat Creek Coal have greatly increased since the assessment in Table 4.1 was made. Using these low cost estimates and comparing them with the cost of alternative generation modes, we see in Table 4.2 that the Hat Creek project is by far the most expensive.

A second thermal generation station--the East Kootenay Project--is also being considered for development in British Columbia.[4] An early study recommended the use of washed, reject coal, but as this increased the costs of the project the most recent feasibility study included a preparation plant onsite. Although any one of several mines in the Southeastern area could supply the required coal, the primary source would be the B.C. Coal Ltd. Balmer property. It is from reject coal at this site that the following figures on content were derived:

Total moisture	8 - 20%
Ash	30 - 49%
Volatile matter	22 - 24%
Fixed carbon	54 - 57%
Sulphur	0.22 - 0.30%

The energy content of the rejects, after washing, is 18.58 MJ/kg or 8000 Btu/lb.

Under the reference scheme, 2.4 million tonnes of unwashed, dry rejects would be washed at an onsite preparation plant with a rewashed yield of 75 percent. Four 150 MW units totalling 600 MW (net) capacity would then utilize 1.8 million tonnes of rewashed coal annually. Cost estimates are currently being updated by the B.C. government. The cost of the reject coal is uncertain as negotiations between B.C. Hydro and the coal producers never proceeded beyond the initial stage, but can be estimated at around $10 per tonne.

TABLE 4.1

ESTIMATED UNIT COST OF ELECTRICITY GENERATION:
HAT CREEK STATION
($1981)

Cost	Mills/kW.h
Capital Cost	16.83
Operating and Maintenance Cost	4.70
Fuel Cost	14.87
Total	36.40

SOURCE: F. Rahnama, Coal and Nuclear Fuels: A Regional Analysis (Calgary: Canadian Energy Research Institute, June 1982), Study 15.

TABLE 4.2

ESTIMATED UNIT COST OF ELECTRICITY GENERATION:
BRITISH COLUMBIA
($1981)

Project Type	Cost Mills/kW.h
Hat Creek Station	36.40
Nuclear	30.19
Hydro	18.30

SOURCES: F. Rahnama, Coal and Nuclear Electricity Fuels: A Regional Analysis (Calgary: Canadian Energy Research Institute, June 1982), Study No. 15; and British Columbia Hydro and Power Authority.

NOTE: Figures shown are for average 80 percent capacity utilization and do not include transmission costs which would further escalate the figures for the Hat Creek project above the other two figures.

As the washed reject coal is of a higher energy content than Hat Creek coal, the two projects may prove to be highly competitive on a unit cost basis. The East Kootenay Project has an environmental edge: wastes are burned in the process rather than being a by-product of the project, necessitating disposal. The characteristic which will most likely decide which project will be initiated first, is output capacity. The Hat Creek plan would be most successful and cost competitive should a large generating capacity be required, whereas the East Kootenay Project would be a project of lesser output.

4.2 Coal Liquefaction

Coal liquefaction is receiving increasing attention worldwide as a means of meeting part of energy demand. In Canada, several project groups have been formed and feasibility studies are underway to ascertain the technical and economic risks involved. In British Columbia, research and development into coal conversion has been gaining support from both industry and government.[5]

Coal liquefaction has traditionally been characterized into two distinct routes: indirect and direct. Indirect liquefaction is achieved by gasifying coal to a mixture of carbon monoxide and hydrogen from which liquid hydrocarbons are synthesized, either directly by the Fischer-Tropsch synthesis or via the methanol route using the Mobil process. The Fischer-Tropsch approach is used in the Sasol plant in South Africa and is the only 'commercial' coal liquefaction process in the world today.

Direct liquefaction involves no intermediate steps. Coal is transformed into liquids in a single step. Although various techniques for coal liquefication are available, direct techniques are still limited in application. Various coal liquefaction processes that are technologically possible are shown in Appendix B. These processes are technically operational and have been tested in pilot plants. Appendix B provides a more in-depth explanation of the liquefaction process.

In British Columbia the best apparent candidate coal for a liquefaction development is Hat Creek, a borderline between sub-bituminous and lignite coal. Hat Creek has large strippable reserves with limited alternate uses, and is owned by a single entity and the ultimate user--B.C. Hydro.

Generally, coals with higher volatile matter are preferred for coal liquefaction. Other coal deposits in British Columbia may be suitable, but alternative uses are more attractive, or the deposits are not large enough to be economical for such large capital expenditures. The Northeast and Southeast coals are highly suitable as metallurgical coal. Information on other coal deposits in British Columbia suggest they have limited potential for conversion.

The British Columbia Energy Development Agency has sponsored research activities throughout the province to provide sufficient technical data to identify and evaluate coal conversion opportunities. Primary emphasis is on the evaluation of British Columbia coal for direct liquefaction but tests are also being carried out to determine gasification potential.

As far as the cost data is concerned, no estimates are yet available for carbonization or hydrogenation processes on a large scale. However, recent studies of Hat Creek coal, using the Sasol process which has been employed in South Africa for some time, indicate that a coal liquefaction plant producing 8000 cubic metres (50,000 barrels) of liquid fuel per day calls for an investment in plant and equipment of around 6.5 billion dollars (1981 $Cdn.).[6]

In order to obtain 8000 cubic metres of liquid fuel, the above plant would use approximately 50 000 tonnes of coal per day, 80 percent being used in the liquefaction process and 20 percent in steam generation. In other words, over six tonnes of coal is used per cubic meter of oil produced. It should be noted that an advanced hydrogenation process may get more than twice the amount of oil from a tonne of coal if the ash and moisture content were low (Hat Creek coal contains a high amount of moisture and ash).

The operating cost for a Hat Creek coal liquefaction plant has been estimated to be in the vicinity of 800 million dollars ($1981) as compared to 330 million dollars for an oil sands plant and 350 million dollars for a heavy oil recovery operation of the same capacity.[7]

The operating cost mentioned above also includes the cost of raw materials, that is, natural gas (for its hydrogen) and coal. It has been estimated that a Sasol-type coal liquefaction plant could produce 1 to 1.5 cubic metres of liquid fuel from six tonnes of coal (1-1.5 barrels per tonne). If this is so, the annual cost of coal for the liquefaction plant producing 8000 cubic metres of liquid fuel per day would be between 146 million and 220 million dollars. These figures are based on $12 per tonne mining cost of Hat Creek coal ($1981).

The above information can be transformed into a present value unit cost for the proposed Hat Creek liquefaction project over its 35-year life. Assuming ten years of lead time for both licensing and construction, the Hat Creek project could produce liquid fuel by 1993 if procedures start in 1983. The present value of the average cost, that is, the minimum unit price required to make the present value of total cost equal to the present value of total revenue for the proposed Hat Creek liquefaction plant, is shown in Table 4.3.

TABLE 4.3

AVERAGE PRESENT VALUE OF PRODUCTION COST
FOR THE HAT CREEK LIQUEFACTION PLANT
($1981/$m^3$)

	Average Present Value Discounted at 6%
Capital Cost	187.44
Operating and Maintenance Cost	253.98
Cost of Coal[a]	56.48-85.10
Total[a]	497.90-526.52

[a]The first number corresponds to the 1.5 barrels of liquid per tonne, while the second relates to a coal-liquid ratio of one.

It should be noted that mining capital costs are not included in the coal price. In other words, the marginal cost of coal mining is considered here. In general, run-of-mine coal costs in British Columbia vary between $15 and $25 per tonne. On the other hand, the large resource-base and accessibility of the Hat Creek deposit reduces mining costs and hence a price of coal between $12 and $15 per tonne results.

A combination of power plant and liquefaction facilities using pyrolysis would reduce both capital and operating costs of the latter plant, as well as the fuel costs of the power station. Fuel costs comprise the major part of the unit electricity generation cost.

Table 4.4 gives a rough indication of the costs of liquids obtained through conventional methods relative to those from oil sands and liquefaction projects.

TABLE 4.4

COMPARISON OF LIQUID FUEL PROJECTS
(1982 $Cdn.)

Project Type	$/bbl of Output
Coal Liquefaction (Cost for 50 000 bbl/day Plant)	75.00-100.00
Synthetic Crude (New Oil Reference Price)	43.37
Conventional Crude (Blended Price at Montreal)	33.70

SOURCES: Corpus, "Energy Pricing News," December 1982; and International Energy Agency (IEA), Coal Liquefaction: A Technology Review (Paris: Organization for Economic Co-Operation and Development, 1982).

As there is no price available as yet for fuel resultant from liquefaction plants, the IEA study assumed a 10 percent (after tax) required rate of return, making the $/bbl figures of the three projects comparable. In addition, this

liquefaction project is similar in size to the Hat Creek Project and is comparable in cost--$6.0 billion (1982 U.S.) for the IEA plant versus over $7.2 billion (1982 Cdn) for the Hat Creek Project.[8] It must be emphasized that liquefaction product cost can vary extensively, according to different circumstances and assumptions, hence the wide range shown in Table 4.4. Even when cost at the low end of this range is assumed, it can be seen that the costs associated with coal liquefaction are high relative to alternative fuels.

In addition to capital cost calculations, other economic parameters including inflation impacts on variable costs such as the cost of employment, do not favour liquid fuel production from coal. Studies on this matter show that for the above hypothetical Hat Creek coal liquefaction plant, some 18,000 workers would be needed during the peak construction phase and operation would involve some 3,500 employees (including 1,500 mine workers). However, the same investment in the Syncrude-type plant would employ 10,000 workers during its peak construction and require 3,000 employees for its operation. This shows that the type of plant which is planned for Hat Creek is more labour intensive than oil sands and heavy oil projects. Although economies of scale may lower costs per barrel of liquid fuel produced at synthetic plants, actual cost figures for a coal liquefaction project may also be underestimated, given the lack of experience with actual projects and high inflation in the construction industry.[9]

It should be noted that other factors are pertinent for consideration of the viability of coal liquefaction in British Columbia. British Columbia obtains more than 75 percent of its liquid hydrocarbon supply from outside the province (although British Columbia is rich in natural gas) either as crude oil or refined products. This deficit is projected to increase by the early 1990s. While the main economic factor, the crude oil price, is not favourable to coal liquefaction, other economic and political factors may favour investment in that option. The latter factors include improvements in either the national or provincial balance of payments, employment generated directly or indirectly as a result of such projects (as was noted earlier, a liquefaction plant employs a large number of people), and finally, a

positive step towards self-sufficiency of liquid fuel supply. A precise analysis of the impacts of a liquefaction plant in British Columbia would require an in-depth study. This is beyond the scope of the present work.

4.3 Industrial Markets in British Columbia

A number of energy-intensive industries within British Columbia currently utilize thermal coal, and have the potential to significantly increase usage. These include the cement and lime industries.[10]

Coal has been a common energy source for cement production for many years and a viable energy alternative. In fact, fly ash can actually be incorporated into the clinker without any negative effects on cement quality. High sulphur levels also present little problem. As an energy intensive industry, cement manufacturing costs are very sensitive to input fuel costs. British Columbia produces only about 10 percent of the country's cement, although excess capacity is available should the market warrant.[11] If coal prices remain competitive, there is an increasing potential provincial market in the cement industry.

The total potential demand for coal in the lime industry is relatively small, although conversion costs are justifiable if thermal coal costs remain below alternative fuels.[12]

Although other provinces have significant potential for coal use in the pulp and paper industry, this is not the case in British Columbia. There, more than 80 percent of all trees cut are utilized by sawmills, plywood mills and shingle mills which produce enough wood waste to meet their energy requirements. Sufficient hog fuel is also made available to the pulp industry, leaving no room for coal penetration.

In conclusion, certain energy-intensive industries do present a market for British Columbia coal producers, albeit quite small in the short term. Conversions to coal are fairly economical, and should any of the industries noted experience a growth period, coal has a good chance of expanding into this market on a larger scale.

4.4 Gasification

Since British Columbia is rich in natural gas, the coal gasification option is not an attractive alternative. The natural gas deposits are widely distributed and the reserves are large enough to support provincial needs, as well as the export market for a number of decades. An estimate of British Columbia's established natural gas reserves as of December 31, 1981 was presented in the Govier Commission report released in May 1982. Marketable natural gas reserves are set at 240 billion cubic metres.[13] Estimated annual consumption for 1981 was about 5 billion cubic metres and requirements are expected to grow at an average annual rate of approximately two percent.[14]

Footnotes

[1]Statistics Canada, Coal and Coke Statistics, Catalogue #45-002, December 1980 and 1981.

[2]Globe and Mail, August 25, 1982.

[3]S. A. Ridley, "Hat Creek Project Described," presented at the Conference "Perspectives on Hat Creek Coal," October 14-16, 1981 in Kamloops, B. C., Table 2.3.

[4]The information quoted below is from the "East Kootenay Project Feasibility Study," as completed by Energy Mines and Petroleum Resources British Columbia in 1978.

[5]The B.C. Energy Development Agency is assessing the liquefaction potential of the Hat Creek coal deposits.

[6]Graham Kedgely, "Coal Conversion in British Columbia, A Status Report," presented to the 33rd Annual Canadian Conference on Coal in Regina, September 20-21, 1981.

[7]Jack Davis, "The Economics of Hat Creek Coal," presented at the Conference "Perspectives on Hat Creek Coal," October 14-16, 1981 in Kamloops, B.C.

[8]International Energy Agency (IEA), Coal Liquefaction: A Technology Review (Paris: Organization for Economic Co-Operation and Development, 1982), p. 28. An interesting discussion of the Canadian situation can be found in E. D. Jamieson and M. Taherzadeh, "Western Canada Coal Liquefaction Study," presented at the CANMET Coal Liquefaction Contractor's Review Meeting in Ottawa, November 8-9, 1982.

[9] W. Kalkreuth, "Liquefaction--An Alternative Technology for Coal Use," presented at the Conference, "Perspectives on Hat Creek Coal," October 14-16, 1981 in Kamloops, B.C.

[10]Canadian Resourcecon Limited, "Potential Markets for Thermal Coal in Canada, 1978-2000," (Calgary: Canadian Energy Research Institute), Working Paper No. 79-2, June 1979. This paper addresses many of these markets on a regional basis.

[11]Ibid., p. 97.

[12]Ibid., pp. 117-118.

[13]The Province of British Columbia, Commission of Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas Liquids: Summary Report (Victoria: The Province of British Columbia, May 1982), p. 7.

[14]Ibid.

Chapter 5

SUMMARY AND CONCLUSIONS

It is difficult to predict levels of British Columbia coal production because demand is heavily influenced by external forces, often causing large swings even in the short-term. The world coal picture as we enter 1983 is indeed bleak in the short-run, although an economic upswing could promote significant development in the latter half of the 1980s. Specifically with regard to British Columbia, the Hat Creek and East Kootenay thermal generation projects are on hold indefinitely; mines have encountered temporary shutdowns because Japanese buyers have reduced contracted imports; and some rail line construction, such as the CPR's Rogers Tunnel project, has been postponed due to less than anticipated traffic flows. There are also some bright spots: Northeast British Columbia Development is progressing close to schedule; coal importers are beginning to diversify their sources leaving the door open for British Columbia coal penetration into new market areas; and the concept of electrification of railways has been given a boost by industry and government alike. All in all though, the number of options available are very limited under current and anticipated coal market conditions.

5.1 Currently Uneconomic Options

As discussed in Chapter 4, the utilization of Hat Creek coal reserves for electricity generation is currently uneconomic. Hydro generation is less costly, and there is considerable surplus generation capacity in British Columbia. Demand for electricity may increase sufficiently to warrant construction of a Hat Creek generating station, but this will not occur for some time. Regarding the East Kootenay generation plant, updated cost estimates may show the project to be competitive with the Hat Creek proposal. Here again, demand considerations will delay any construction well into the 1990s. There is one more point to be mentioned about these projects. B.C. Hydro holds the leases on the Hat Creek

coalfield but the coal utilized in the East Kootenay project would have to be purchased from corporate supplies under contract. There is, therefore, an element of uncertainty associated with coal costs in the case of the latter project.

Of the other domestic development options outlined in Chapter 4, both the Hat Creek liquefaction and coal gasification proposals are not viable on a commercial project-scale basis. Falling crude oil prices and relatively cheap surplus natural gas will mean that ventures of this type will more than likely not be undertaken until the next century, except in the case of pilot, experimental/demonstration scale plants.

The throughput required for construction of a coal slurry line is not available in British Columbia unless a great number of the proposed projects are realized. The existing Southeastern rail routes appear to be able to handle coal shipments to the west coast in the near-term. Capital requirements for expansion and upgrading of rail lines may be met to a large extent by funds made available through revisions to the Crow Rate. There is also more time to amass capital required for the construction due to delays of some rail projects. As for the Northeast route, a new rail spurline and expansion to existing facilities will provide sufficient capacity for the transport of coal from the two coal projects under construction, as well as excess capacity for further development.

5.2 Feasible Options

The small industrial sector of British Columbia is emerging as a market for part of the coal produced within the province. In particular, the cement industry offers the greatest potential for coal use, while the lime industry is a lesser source of demand. The total market for British Columbia coal for these industries is quite small relative to other users, especially in other countries, but does offer a small alternative to the export option discussed below.

Quintette and Bullmoose mines will be operational early in 1984, and benefits to the province and to Canada

will be significant if export levels are maintained at those contracted.

In the latter part of this century, thermal coal markets will show the greatest expansion, while metallurgical demand will increase relatively slowly on an international scale. Consequently, B.C. producers have been studying thermal coal development, and are attempting to develop their thermal coal reserves and markets. As the bulk of Canadian thermal coal exports previously originated in Alberta, B.C. producers will infiltrate this market only if quality considerations do not preclude most British Columbia coal. The coal is low-volatile for the most part, and hence unacceptable under many nations' quality requirements, especially Japan.

It appears that coal producers protected by long term contracts negotiated during 1981 or earlier, will be in a favourable position. Contracts, however, are in many cases periodically renegotiated to reflect changing market conditions. Returns to producers may be lower than anticipated for the time being, but the international coal market and coal prices are projected to begin to strengthen in the latter half of the 1980s. In short, the export market potential for both metallurgical and thermal coal remains fairly bright over the longer-term. Increased rates cannot, however, be taken for granted. Aggressive marketing strategies based on competitive costs and reliability of deliverability in comparison with Australia and Canada's other competitors will be essential.

APPENDIX A

MARITIME TRANSPORTATION COSTS DETAILED

Appendix A

MARITIME TRANSPORTATION COSTS DETAILED

The basis for the determination of these tables comes from H. M. Lee, The Long Run Economics of the Ocean Transport of Coal, Report No. D1/78 (London: IEA, December 1978), Appendix.

Total shipping costs per tonne are the sum of:

Capital Charges = (Cc • Cr/Dy) • Dt/Tt
Operating Costs = (Oy/Dy) • Dt/Tt
Fuel Costs = Fc • Ft/Tt
Port and Canal Dues = Pd + Cd

Formulae used:

Dt = Dl + Dp + Db
Dl = Ld/24Kn + Tc
Db = Bd/24Kn + Tc
Tt = Dw - (Fs + Sd) • Dl
Ft = Fs • (Dl + Db) + Fp • Dp

Symbols defined:
Bd = Ballast distance
Cc = Capital cost of ship
Cd = Canal dues
Cr = Capital charges per year
Db = Days in ballast
Dl = Days loaded
Dp = Days in port
Dt = Days per trip
Dw = Deadweight capacity of ship
Dy = Operating days per year
Fc = Fuel costs per tonne of fuel
Fp = Fuel consumption in port
Fs = Fuel consumption at sea
Ft = Fuel per trip
Kn = Operating speed
Ld = Loaded distance
Oy = Operating costs per year

Pd = Port dues per tonne
Sd = Stores per day
Tc = Time lost in canals
Tt = Tonnes per trip

Table B.1 shows the numerical assumptions associated with the formulae above.

TABLE A.1

ASSUMPTIONS FOR SHIPPING COST ESTIMATES
(1982 $Cdn.)

			Ship Size (dead weight tonnes)			
			60 000	100 000	150 000	200 000
Capital cost	OF	10^6	38.9	49.1	62.6	79.5
	CF		45.8	57.5	72.8	91.4
Annual operating costs	OF	$10^6$$/yr	2.8	3.3	3.9	4.8
	CF		2.9	3.4	4.0	4.9
Fuel costs per tonne of fuel	OF	$/t	237.5	237.5	237.5	237.5
	CF		68.8	68.8	68.8	68.8
Port dues per tonne carried	OF	$/t	1.9	1.9	1.9	1.9
	CF		1.9	1.9	1.9	1.9
Operating speed	OF	knots	13.0	13.0	13.0	13.0
	CF		16.0	16.0	16.0	16.0
Fuel consumption at sea	OF	t/day	35.0	45.0	55.0	65.0
	CF		130.0	170.0	205.0	240.0
Fuel consumption in port	OF	t/day	3.0	3.0	3.5	3.5
	CF		8.0	8.0	9.0	9.0
Days in port per trip	OF	days	6.0	7.0	8.0	9.0
	CF		6.0	7.0	8.0	9.0
Operating days per year	OF	days	345.0	345.0	345.0	345.0
	CF		345.0	345.0	345.0	345.0

SOURCES: International Energy Agency, Canada West Foundation and Canadian Energy Research Institute.

NOTE: OF - designates oil-fired vessels CF - designates coal-fired vessels

APPENDIX B

COAL LIQUEFACTION PROCESSES

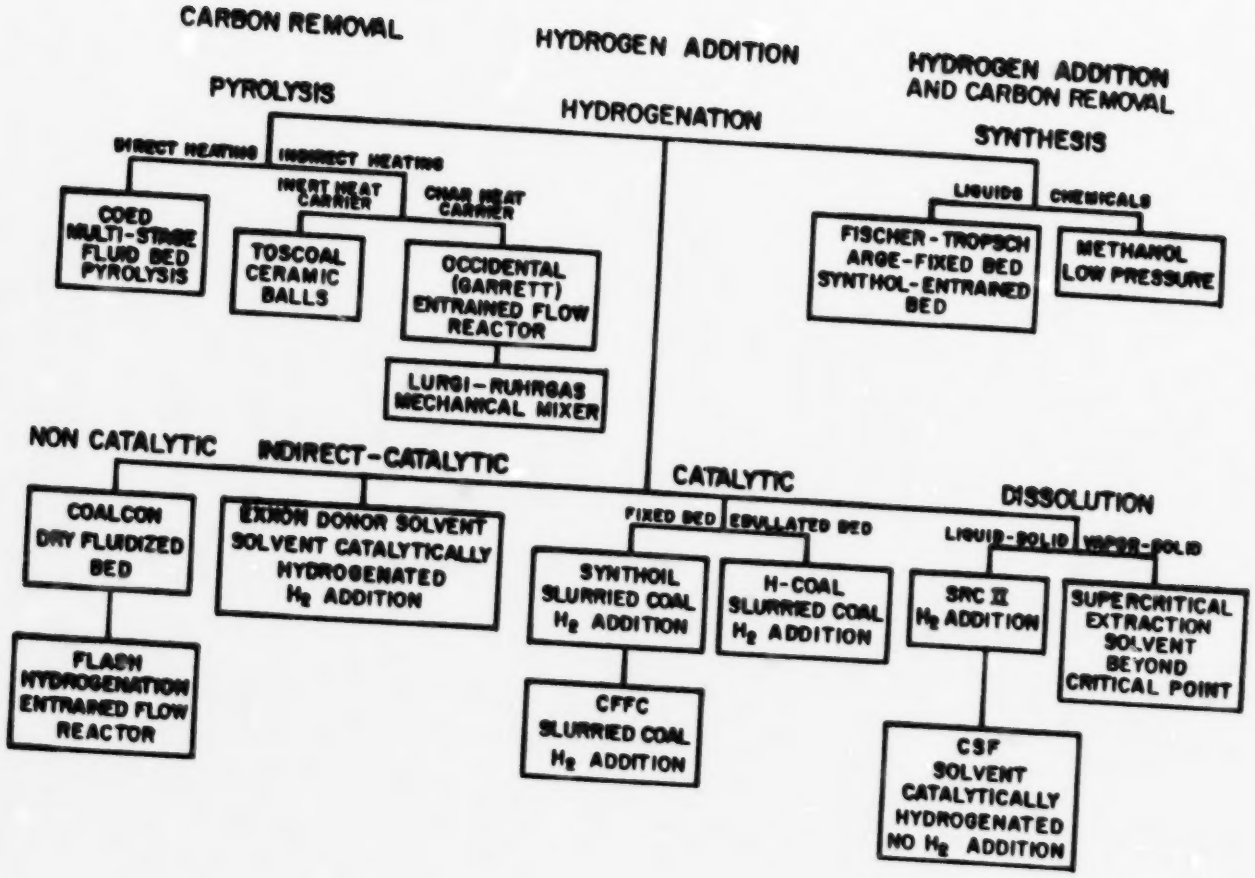
Appendix B

COAL LIQUEFACTION PROCESSES

Liquid fuel is derived directly either from a degradation process using hydroliquefaction, or by pyrolysis. Figure B.1 outlines the various processes. In the first approach coal is fed into a reactor in the form of a slurry and reacted with hydrogen under high pressure and in the presence of catalysts. Hydrogen can be either added as a gas or donated by a hydrogen-rich solvent which can be recovered after the process. The primary liquids formed are then upgraded to form liquid fuels. Numerous modifications of this basic hydroliquefaction process are currently under investigation. One of the most interesting of these is an extraction process in which the coal is dissolved in a strong solvent prior to hydrogenation. Synthesis gas (mixture of H_2 and CO) is used to increase the rate of conversion, with water acting as a carrier medium and hydrogen-doner. Hydroliquefaction may yield 0.31-0.55 cubic metres (2.0-3.5 barrels) of liquid per tonne of coal.

The second process, pyrolysis or carbonization in which coal is heated in the absence of air, is the simplest of the three processes (hydrogenation, pyrolysis, and synthesis) for producing oil from coal. Liquid yields reported in the literature are generally low (maximum 35 percent). Conversion might be improved by a new method called flash-pyrolysis, where coal is heated much more rapidly in the presence of hydrogen, leading to increased liquid and gas yields. The latter process also yields an improved burning char, which is the primary result of pyrolysis. The char or coke is carbon-rich and can be gasified to produce hydrogen for the upgrading process.

There are numerous published reports on the capital and operating costs of the various liquefaction processes. The estimates differ due to varying base years, inclusion of mining costs, inclusion of infrastructure costs, the scale of the project, liquefaction process used, and so on. Faced with these difficulties, one should expect that the only



SOURCE: Herring I.W. and E. L. Tollefson, "The Economics of Coal Liquefaction in Alberta by Low Temperature Flash Pyrolysis as a Precursor to Thermal Electric Power Generation," presented to the Canadian Gas Processors Association in Calgary, November 1979.

Figure B.1: Coal Liquefaction Processes

reliable cost estimates for such plants are those based on extensive experience with operating plants such as Sasol I in South Africa.[1] It is difficult to transpose the Sasol I costs to a liquefaction project in British Columbia. This is due to the differences in labor market, structure of environmental regulations, state of the economy, and in coal characteristics. General economic comparisions can be made, as was seen in Chapter 4 of the text.

In terms of technical aspects, direct liquefaction processes have the following advantages:

- high thermal and thermo-dynamic efficiences;
- high production of liquids; and
- possibility of production of a large product slate.

Flash-pyrolysis, the heating of coal in a short time period is advantageous since liquid yields are maximized. The most technically advanced pyrolysis process is the Lurgi-Ruhrgas process which has been operating commercially in Yugoslavia since 1963.

The advantage of carbonization is that it requires lower investment compared with other liquefaction routes. It also features a relatively low specific hydrogen requirement per tonne of liquid product since only hydrogen-rich liquid components are fed in the hydrogenation step. The only disadvantage is its limited application. This method should thus be considered when tar-rich coal is available. Economic viability requires a sufficient market for the large quantities of char produced as a byproduct, such as a large power plant. A pyrolysis/power plant could prove a practical combination.

Direct liquefaction processes should be preferred whenever the coal being developed has the petrographic characteristics required for conversion. If the coal is insufficiently reactive, the other routes can represent convenient alternatives for producing liquid fuels.

Current work in the U.S., Europe, Japan and Australia is resulting in renewed evidence that direct liquefaction is a promising route for coals having a substantial percentage of reactive minerals (nitrinite plus extrinite). Although coal liquefaction is technologically viable, it will probably be a decade before economic conditions are favourable. The present crude oil market, with declining real prices forecast for the next two or three years, have rendered such operations economically unattractive.

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